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STRATEGIC PETROLEUM RESERVE OIL STORAGE CAVERN WEST HACKBERRY 6 RECERTIFICATION TESTS AND ANALYSIS

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Abstract

The final cavern pressure test and well leak test made in June-July 1981 indicated combined oil leakage from the three cavern entry wells will be well within the DOE leak rate criterion of 100 bbls/yr per cavern at the most severe design operating conditions of the cavern. The tests did not indicate conclusively that there was no leakage from the cavern other than from the wells. However, they did give a positive indication of no leakage to cavern 9, the nearest cavern about 200 feet away. It is believed that serious structural failure of the cavern is unlikely during long term oil storage at normal pressures, or during accidental depressurization to oil head pressures.

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INTRODUCTION

Cavern 6 at the West Hackberry, Louisiana SPR oil storage site was certified for oil storage on November 8, 1977. Following certification, approximately seven million barrels of crude oil were stored in the cavern, with the last oil being stored on September 13, 1978. On September 21, 1978[1], a blowout of cavern entry well 6 occurred during workover. An estimated 72,000 barrels of oil were spilled from the cavern causing depressurization from storage pressure of about 1900 psi to 1250 psi at the cavern roof.

This accidental deptessurization represents a severe cavern loading condition with pressure inside the cavern, acting as a balance against lithostatic pressure, probably being lower than since the beginning of cavern formation. Such loading conditions are generally avoided because of large reductions in compressive stresses in the salt. Such conditions are of special concern for a cavern such as West Hackberry 6 with a flat roof of such large diameter (about 1150 feet).

Because of the concern that the integrity of Cavern 6 might have been affected by the depressurization, a decision was made by the Department of Energy Strategic Petroleum Reserve Project Management Office (DOE/SPRPMO) to remove the oil and recertify the cavern. The oil was removed, the wells worked over, various logging and diagnostic procedures performed, and a cavern pressure test was conducted in September-October 1980. Analysis of the pressure test results indicated large cavern leak rates at maximum operating pressures, though the magnitude could not be defined because of limited data and inability to accurately calculate the effect of salt creep. A test procedure was developed for determining leaks from cavern wells independent of salt creep effects. A well leak test was made in January-February 1981 which indicated substantial leaks from 2 of the 3 cavern wells. Well workovers to repair the leaks were made and a second cavern pressure and well leak test made in June-July 1981 indicated acceptable well leak rates and cavern structural behavior.

This report includes a general history of the cavern, and a record and analysis of recertification activities and test results.

HISTORY

Cavern 6 at the West Hackberry, Louisiana SPR storage site is a large diameter dish shaped cavity[2], Figure 1, with a total volume of about 8.6 x 10^6 bbls. When the cavern became part of the SPR program, it had a single entry well, well 6, with a 12 7/8-inch production casing set to 2632 feet[3], Figure 2. As part of the initial cavern certification activities, a cement bond log, a cavern sonar caliper survey, and an azimuth and deviation survey were run, and a 9 5/8-inch liner was cemented into the 12 7/8-inch casing to a depth of 2603 feet[3,4]. The sonar caliper survey of June 6, 1977 indicated a total cavern volume of 12,155,044 barrels, compared with an earlier survey by Olin Corporation on March 5, 1975, which had indicated a total cavern volume of 14,583,000 barrels. The cavern shapes indicated by both surveys were grossly different from the shape of Figure 1, presumably because of misinterpretation of the raw data.

The brine filled cavern and well system was hydrostatically tested to a wellhead pressure of 715 psi for 24 hours. The certification document[4] states that less than a 10 psi pressure drop occurred during the 24-hour test. The cavern was certified by Gulf Interstate Engineering Company (GIEC) for storage of crude oil on November 8, 1977.

On September 25, 1977, drilling operations began on reentry well 6-B by GIEC[5]. The operation was halted on November 11, 1977, at a depth of 3208 feet (true vertical depth of 3186 feet) after all cemented casing strings had been installed as shown in Figure 2. Drilling was resumed on July 3, 1978 by Louis Records and Associates, Inc.[6] The cavern was entered on July 14, 1978. The well was logged by both GIEC and Louis Records[5,6]. The well histories do not indicate that a pressure test of the casing seat was performed. A 9 S/B-inch brine string was hung to a depth of 3365 feet.

Reentry well 6C was drilled and completed to cavern entry by Louis Records beginning on June 26, 1978, with completion on August 4, 1978[7] (Figure 2). The 13 3/8-inch casing was tested to 950 psig surface pressure. The well was logged and cored from 2194 feet to 2250 feet. A 9 5/8-inch brine string was hung to a depth of 3365 feet. (During the last well workover, hanging string depth was increased to 3374 feet, as shown in Figure 2.)

Both wells 6B and 6C entered the cavern after oil storage had begun.

Drilling operations began on reentry well 6A[8] on August 8, 1978, and drilling was suspended at a depth of 2240 feet on September 21, 1978, as a result of failure of a seal in well 6 and consequent cavern depressurization and an oil fire. This well (Figure 2) penetrated the top of the salt but did not enter the cavern. After extinguishing the fire, the drill pipe was cut, allowing approximately 2000' of drilling assembly to fall to the bottom of the hole.

References 7 and 8 state that depths for wells 6A and 6C in Figure 2 are referenced to the rotary table of the drill rig, which is typically several feet above the ground level and Bradenhead flange. It is presumed, though not certain, that depths for the other two wells of Figure 2 have the same reference location. It is noted that the 7-inch cemented casing of well 6 had not been installed at the time of the cavern accident. The well was being operated with a 5 1/2-inch hanging string inside the 9 5/8-inch liner. As a result of the accident, 2834 ft. of the 5 1/2-inch casing was dropped and probably has fallen into the cavern, as it is not now obstructing the well bore.

Locations of the wells and the relation of cavern 6 to the nearest caverns are shown in Figure 3. Relative locations of boreholes at cavern roofs were obtained from azimuth and deviation surveys[4,9].

On September 21, 1978, the 5 1/2-inch hanging string was being pulled from well 6 when a bridge plug near the bottom of the string failed, causing a well blowout. It was not possible to cap the well, and the oil flowing from'the well caught fire and burned 5 days before the well was capped. During the fire an estimated 72,000 bbls was spilled, and 52,000 bbls of'the spilled oil was recovered and stored in other site caverns. As a result of the blowout and loss of oil, the pressure at the cavern roof was lowered from about 1900 to 1250 psi and the useability of Cavern 6 as a crude oil storage cavern was reexamined. The DOE/SPRPMO decided to attempt to recertify the cavern, and Jacobs/D'Appolonia Engineers (JDE) prepared a recertification plan[10]. The JDE plan was subsequently modified by Texas Brine Corporation (TBC) and Sandia National Laboratories[11,12] and approved by SPRPMO before recertifiction activities were started.

Oil withdrawal began on October 19, 1979, and was completed on February 3, 1980. During the period of oil withdrawal TBC measured the volume of crude oil withdrawn, and periodically logged the oil/brine interface depth. Comparisons of measured interface movements with expected interface movements for the volume withdrawn suggested significant inaccuracies in the cavern sonar caliper survey performed in 1977[4]. The inventory volume of oil remaining in the cavern following the accident was 6,899,447 net bbls (volume at 60°F and atmospheric pressure).

TBC, under contract to Dravo Utilities Construction, Inc. (DUCI) began workovers and logging wells 6B and 6C in February 1980 and completed these activities in April 1980.

Williams Brothers/Fenix and Scisson (WF&S) began workover and logging of well 6 in April 1980 and phase 1 of the workover was completed in May 1980. After review of the logs obtained on well 6, the *decision was made by DOE/SPRPMO on May 23, 1980, to run and cement a seven-inch production casing into the salt. Cementation of the casing to a depth of 2750 feet was completed in September 1980[13]. The well 6 configuration following this workover is that shown in Figure 2.

The first recertification pressure test using the approved plan began September 20, 1980 and terminated October 10, 1980[14]. Test results indicated a cavern pressure decay rate of about 1.0 psi/day at maximum operating pressure. Analysis indicated that. the leak rate corresponding to this pressure decay rate was quite large, but could not be precisely determined because of inability to determine the effects of salt creep on pressure. The analysis further indicated that even if salt creep effects could be predicted, limitations on measurement accuracies would result in predicted leak rate uncertainties of possibly ± 4000 bbls/yr.

Because of the indeterminate effects of salt creep and the large uncertainties in predicted leak rates due to measurement limitations, procedures were developed for well leak tests which would not require a knowledge of salt creep effects and would be less sensitive to measurement limitations[15]. The logic leading to this procedure was a follows; the probability is high that any cavern leaks will be in the vicinity of wells where the competent salt has been breached,' and therefore, that well leaks will equal total cavern leaks. The procedure involves filling the well (slick hole) or well annulus with nitrogen to a depth below the casing seat; allowing a stabilization period for the nitrogen temperature to reach quasi equilibrium with the borehole; and then measuring the volume loss of nitrogen over a period of time using interface measurements. The use of nitrogen has a disadvantage in that considerable effort is required to correlate nitrogen and oil leak rates but is probably superior to the use of oil in caverns previously used for oil storage. An attempt to measure well leak rates during the first recertification test using oil filled wells and a brine filled cavern was completely unsuccessful. Oil from traps in the cavern roof was released into the wells, due to cavern roof flexing when the cavern was pressurized, and completely masked any effects of oil leakage from the wells.

A nitrogen well leak test was made during the period January 8-26, 1981[16]. The test indicated substantial nitrogen leakage from well 6C (2290 bbl/yr) and significant nitrogen leakage from well 6 (554 bbls/yr). DOE/SPRPMO decided to try to repair these two wells. Texas Brine Corporation attempted to locate and repair leaks in these wells during April and May 1981. A possible leak at the 13 3/8-inch casing hanger at the wellhead of well 6C was indicated, and an adjustment to the hanger was made. Attempts to set cement plugs in the open boreholes below the casing seats for casing seat and casing tests were unsuccessful. Attempts to locate leaks in the casings were also unsuccessful because of inconsistent and uncertain casing packer performance. Workover attempts were terminated and DOE/SPRPMO decided to make another attempt to recertify the cavern following the same cavern test plan and nitrogen well test procedures.

A cavern pressure test and well leak test was started June 6, 1981, and completed July 12, 1981. Results of this test indicated satisfactorily low leak rates, and oil storage in the cavern was started July 13, 1981.

LOGGING AND OTHER DIAGNOSTIC ACTIVITIES

Results of mineralogy and structural testing of salt core from well 6C is published in Reference 17. The testing indicates competent salt with mineralogy and mechanical properties of dome salt.

Side wall salt samples were taken from wells 6B and 6C. These samples contained oil within the salt such that the salt was more discolored near the borehole than it was deeper in the formation. The side wall samples were approximately an inch in diameter by 3/4-inch long. The typical amount of oil was 0.3 weight percent in the well 6B samples and 0.1 weight percent in the 6C samples. The larger concentration corresponds to less than 300 bbls of oil absorbed in the surface of the entire cavern.

The hanging strings from wells 6B and 6C were removed in March 1980 and were tested and inspected as defined in References 18 and 19. The conclusion is that after two years of submersion in the salt brine, there is no evidence of significant corrosion. The mechanical property tests verified that the casing meets the strength requirements of API grade K-55 and that the collar meets the strength requirements of API grade H-40.

Many logs were run in the three wells to determine the conditions of the wells. Table I includes a listing of these logs, together with previous logs which are available. Table II includes comments on some of the logs and Table III includes nomenclature for Tables I and II. A selected few of these logs are included in Reference 14.

In addition to well diagnostic purposes, several temperature logs were run over a period of several months to determine the rate of brine temperature change in the cavern, since cavern pressure is strongly dependent on temperature. These logs indicate an average cavern brine temperature increase rate of about 0.01°F/day[14] corresponding to an estimated pressure increase rate of 0.17 psi/day. Results of samples of these logs are presented in Figure 4 primarily to illustrate borehole formation temperature. The results for well 6C relative to the other wells indicate that brine may have been removed from the well a relatively short time before the log was run.

Brine samples at various depths in the cavern were taken at different times over a period of several months to determine the rate of change of brine salinity and thus the rate of salt solutioning in the cavern. Figure 5 is a graph of the difference between saturation salinity and average measured salinity from Reference 14. Although the cavern brine is only slightly unsaturated and the indicated solutioning rate appears quite low, its effect on cavern pressure was estimated in Reference 14 to cause a pressure decay rate of 0.24 psi/day.

Cavern sonar surveys were made through each of the three cavern wells[2,20,21]. Total cavern volumes calculated from the three surveys are as follow:

Well 6	8,605,733 bbls
Well 6B	8,007,157 bbls
Well 6C	8,082,741 bbls

Vertical sections determined from the surveys through wells 6B and 6C are similar to those of Figure 1 for the well 6 survey. The differences in volume are consistent with a quoted radius accuracy of 5-percent from the surveys. Intuition suggests that the survey through well 6, which is nearer the center of the cavern, should be better than surveys through the other wells located over 180 feet away. The oil-brine interface at the beginning of oil *withdrawal was at a depth of 3300.5 feet. The volume of oil removed from the cavern was 563,300 bbls more than the cavern volume above this depth indicated by the sonar survey through well 6.

Following the attempt to locate and repair the leak in well 6 indicated by the January 1981 well leak test, a drill string and a caliper logging tool were lowered into the cavern and indicated the cavern floor was about 8 feet above its previous depth. The drill string lost tension when it contacted the new floor but did penetrate to the original floor depth. This suggested the possibility of some roof fall. An abbreviated sonar survey[22] was made to examine this possibility. The survey indicated the primary change in the cavern floor was an 8-10 foot rise directly under the well 6 entry. The floor appeared to be affected over a radius of 20 to 70 feet, though the effect decreased rapidly with radius. At the cavern roof, the previous survey[2] indicated borehole radii of about 4 to 9 feet at a depth of 3228 feet, whereas the new survey indicated radii of 395 to 431 feet at this same depth. Although these dimensions indicate the loss of a large diameter thin slab, there is considerable question regarding the capability of the sonar to make such a discrimination in the vicinity of a flat roof. It is not possible to draw firm conclusions on the extent of any roof fall, though it appears probable that some did occur.

FIRST CAVERN RECERTIFICATION PRESSURE TEST OF SEPTEMBER-OCTOBER 1980

During the first unsuccessful pressure test[14], a hollow drill string was hung in well 6 and the annuli of the three wells were filled with crude oil to depths well below the casing seats. The cavern was pressurized to a minimum depth casing seat gradient of 0.86 psi/ft, the maximum allowable test gradient, and then shut in for 34 hours. Pressure was then reduced to the maximum allowable operating gradient of 0.80 psi/ft and the cavern was shut in for 7 3/4 days.

Pressure-volume data collected during pressurization and depressurization of the cavern indicated a near constant value of elasticity of about 57 bbls/psi over the pressure range: that is, 57 barrels of brine injected into the cavern or recovered from the cavern resulted in a 1 psi change in cavern pressure.

Pressure results were recorded using several transducer systems with digital recording of pressures. During the shut-in period at maximum allowable test gradient, pressure decay rates appeared to still be decreasing at the end of the shut-in period. However, the decay rate from linear regressions of the last 16 hours of test data indicated pressure decay rates of 15.5 ± 2.1 psi/day.

During the shut-in period at maximum-allowable operating gradient, the pressure decay rate appeared near constant after the first 2 3/4 days of shut in. Linear regressions of data for the last 5 days of this portion of the test indicated a pressure decay rate of 0.98 ± 0.12 psi/day. Analysis of cavern brine temperature and salinity data indicated thermal and solutioning effects could cause a cavern pressure decay rate of 0.06 to 0.15 psi/day. The remaining 0.875 ± 0.165 psi/day decay rate is due to cavern leakage and salt creep and there is no way to separate the two contributions. Since salt creep is normally expected to cause cavern pressure to increase, it appeared that pressure decay due to leakage must be at least 0.875 psi/day. With cavern elasticity of 57 bbls/psi, this pressure decay rate corresponds to a leak rate of 49.9 bbls/day or 18,200 bbls/year.

In consideration of the limitations of conventional pressure testing for accurately determining cavern leak rates, this cavern pressure test included plans for measurement of well leak rates. The well annuli were filled with crude oil to depths below the casing seat; so that oil losses from the wells could be determined from oil brine interface measurements before and after the test. The desired results were not obtained from this part of the test because oil was released from traps in the roof of the previously oil filled cavern, entered the cavern wells during the test, and completely masked any interface movement due to well leaks.

WELL LEAR TEST OF JANUARY 1981

For the well leak test of January 1981, a hollow 2-7/8" drill string was hung in well 6 to a depth well below the casing seat. Nitrogen was injected into the annuli of the three wells to depths of 40 to 80 feet below the casing seats. The cavern was pressurized to about 450 psi wellhead brine pressure. This pressure was limited by the wellhead design pressure of 2000 psi and the relatively high wellhead nitrogen pressure required for the desired nitrogen-brine interface depths. This operating condition corresponds to a minimum depth casing seat pressure gradient of 0.69 psi/ft. Additional nitrogen was added to achieve the desired interface depths and the wells were shut in.

The original interface location in each well was established with an interface log. Interface depths were then measured twice during the subsequent 9 to 10 days. Upward movement of the interface indicated a loss of nitrogen. After the last interface measurements, the weight of nitrogen required to reestablish the original interface depth was measured. Brine pressures were measured at the wellheads of wells 6B and 6C and nitrogen pressures were measured at all wellheads. An attempt to measure brine volume injected during the pressurization was unsuccessful, but volumes removed were measured during depressurization from a wellhead brine pressure of 415 to 260 psia. These results indicated cavern elasticity of 53.0 bbls/psi, compared with a value of about 57 bbls/psi from the previous pressure test.

Cavern 6 pressures measured during the test are shown in Figures 6 to 11. Two pressure probes were used for nitrogen pressure measurements on well 6 (Figure 6 and 7) for redundancy and the pressures indicated by the two probes are near identical. After pressurizing the cavern with brine and resetting the interface, the pressure decayed gradually until about 170 hours, and then varied erratically for about 120 hours. Both probes used a single data processor and a problem was suspected with the processor: however, the processor was changed with no apparent affect. It is now believed that the erratic variations were due to bubbles of oil entering the well and rising through the brine to the nitrogen interface. The pressure plateau reached at about 300 hours began at the time nitrogen was added to reestablish the original interface at the end of the test. The higher pressure at the end of the test, with the same interface depth, is attributed to an increase in oil column height in the borehole.

After pressurizing the cavern and resetting the interface, both the brine and nitrogen pressures for well 6B decreased slightly for about half the shut-in period of about 340 hours and then increased slightly for the remainder of the period (Figures 8 and 9). The brine pressure of well 6C behaved similarly (Figure 10). However, the nitrogen pressure of well 6C (Figure 11) decreased continuously with time. The rapid increase in well 6C nitrogen pressure decay rate at about 260 hours is believed to have been due to the interface rising from the relatively large diameter open borehole into the smaller diameter cased portion of the well. The abrupt increase in pressure at about 290 hours is a result of adding nitrogen to reestablish the original interface at the end of the test.

After the pressures began to rise during the latter portion of the shut-in period linear regressions were obtained for well 6B brine and nitrogen pressure data and well 6C brine pressure data. Results of these linear regressions at a cavern wellhead brine pressure of about 445 psia were as follows:

Data	Elapsed Time Hours	Pressure Increase Rate- psi/day
6B - brine	218 to 386	0.288
6B - nitrogen	218 to 386	0.240
6C - brine	224 to 344	0.624

These pressure increase rates compare with a cavern brine pressure decay rate of 0.98 ± 0.12 psi/day during the first pressure test at about 640 psia. The comparison is consistent with lower leak rates and higher cavern creep closure rates at the lower pressure. Following the leak test, nitrogen was bled from the wells and the cavern was depressurized to 260 psia and shut in. Pressure instrumentation was left on the brine string and annulus of well 6B for about 48 hours. Wellhead brine pressure during the last 24 hours of this period was about 268 psia and the pressure increase rates were near constant, as follows:

Data	Elapsed Time Mours	Pressure Increase Rate - psi/day
6B - brine string	434-458	4.22
6B - annulus	434-458	4.51

Results of the interface depth measurements are shown in Table IV[16]. The results indicate significant upward movements of the interfaces in wells 6 and 6C and a slight downward movement in well 6B. There is a possibility of some nitrogen temperature change between the first and second interface measurements so the second and third measurements were used for volume calculations. Nitrogen volumes at the two interface levels were normalized to a constant pressure. For volume calculations the borehole volume was estimated at; 0.175 bbls/ft for well 6B from injected nitrogen weight and interface depth measurements during a subsequent test; and 1.0 bbls/ft for well 6C from injected oil volume and interface depth measurements during an earlier test. The borehole volume of well 6 was not required because the second and third interface were in the cased portion of the well where the geometry was known. Results of these calculations are as follows:

We 11	Leak Rate bbls/yr
6	43
6B	4
6C	2290

The above leak rates include leakage from both the casing and casing seat of wells 6B and 6C but only casing leakage for well 6. It is noted in Table IV that for well 6, the interface movement between the first and second measurements was 46 feet in 123.5 hours, whereas between the second and third measurements which were used in the calculations it was only 21 feet in 121 hours. In view of the fact that the open hole volume per foot of depth is greater than that of the cased hole, this suggests a considerably greater leak rate below the casing than the 43 bbls/yr calculated above. TO get a rough idea of casing seat leakage for well 6, a volume calculation was made using the first and third interface locations. The calculation thus includes an error due to any nitrogen temperature change following the first interface measurement. For this calculation, borehole volume below the casing seat was estimated at 0.128 bbls/ft from injected nitrogen weight and interface depth measurements. The calculation indicates an average leak rate of 217 bbls/yr. Assuming the leak rate with the interface in the casing is constant at 43 bbls/yr, as calculated above, the interface would have reached the casing seat 161.3 hours before the final measurement, and therefore 83.2 hours after the initial measurement. The resulting rate of movement below the casing seat corresponds to a leak Kate of about 530 bbls/yr.

FOK well 6C, the third interface measurement was 2 feet below the casing seat. An attempt to measure a fourth interface in the casing to get an idea of casing leakage was unsuccessful. Also, an attempt to define interface movement in the casing from measured pressures revealed inconsistencies which could not be resolved. Thus, leak rate after the interface entered the casing could not be defined. During the course of the test, nitrogen was found bubbling to the surface around the wellhead, and the annulus between the 13 3/8-inch and 20-inch casing at the well-head was found to be pressurized to 1860 psi. This was an indication of a possible leak at the 13 3/8-inch hanger.

The leak rates of nitrogen calculated above are greater than rates expected with an oil filled cavern. However, a correlation of oil and nitrogen leak rates is not possible without a much more detailed knowledge of the leak than is possible from tests such as these. It is possible in certain types of leaks for the volumetric loss of oil to be a significant fraction of volumetric loss of nitrogen. It was therefore deemed advisable to attempt repairs of wells 6 and 6C. The leak rate calculated for well 6B was considered insignificant.

During the above test, wellhead pressures on cavern 9 were monitored. Cavern 9 is the nearest cavern to cavern 6 (Figure 3), and therefore, the one most likely to be in communication with cavern 6. Brine and oil pressures from well 9B are shown in Figure 12. The abrupt drop in well 9B pressures at about 220 hours resulted from a bleed off of cavern brine. The increase in pressures at about 408 hours resulted from a transfer of brine to cavern 9 from cavern 6 during its depressurization. Results of cavern 9 pressure change with volume injected indicated a cavern elasticity of 58.5 bbls/psi for brine pressures between about 40 and 200 psia. It is noted that this cavern is oil filled and the elasticity is not directly comparable to that for brine filled cavern 6.

Results of Figure 12 indicate the typical pressure increase with time with cavern 9 shut in at low wellhead brine pressures. Linear regressions were obtained for the oil and brine pressures before the brine bleed off at 220 hours and before the pressurization at 406 hours. The results of these linear regressions, for the record, are as follows:

Data	Approximate Pressure Level, psia	Elapsed Time Hours	Pressure Increase Rate, psi/day
Well 9B - brine	50	160 - 220	1.42
Well 9B - oil	540	160 - 220	1.58
Well 9B - brine	41	356 - 406	1.94
Well 9B - oil	529	356 - 406	1.99

The first 60 hours of data for cavern 9 oil and brine pressures and for well 6B brine pressure have been plotted on expanded scales to illustrate affects of cavern 6 pressurization on cavern 9 (Figure 13). This figure shows cavern 9 pressures generally increasing up to about 28 hours, when cavern 6 pressurization was started. During cavern 6 pressurization, from 28 to 37 hours , cavern 9 oil and brine pressures dropped about 2 psi. Following this cavern 6 pressurization period, cavern 9 pressures immediately started increasing again. These results are considered a positive indication of the absence of communication between the two caverns since the pressure change direction in cavern 9 is opposite to that in cavern 6. The results could be explained as follows: pressurization of cavern 6 causes its roof to rise and this salt motion results in a much smaller motion in the same direction of the cavern 9 roof, with a resulting increase in cavern volume and decrease in cavern pressure.

CAVERN PRESSURE TEST AND WELL LEAK TEST

OF JUNE - JULY 1981

Following workover of wells 6 and 6C after the previously discussed well leak test, a combined cavern pressure test and well leak test was initiated June 6, 1981.

The cavern pressure test included; (1) pressurizing the cavern to maximum allowable pressure with brine; (2) shutting the cavern in for eight days: (3) reducing the cavern pressure to maximum operating pressure; and (4) shutting in the cavern for five days. This phase of the test was the same as the first pressure test with two exceptions, there was no oil initially injected into the boreholes and the length of shut-in period was longer at maximum allowable pressure and shorter at maximum operating pressure. The longer shut-in period at maximum allowable pressure was used in an unsuccessful attempt to reach a steady rate of pressure change with time. The shut-in period at maximum operating pressure was terminated when it appeared that rate of pressure change with time was constant.

Prior to the well leak test and following the shut-in period at maximum operating pressure, the cavern pressure was reduced to 450 psi and the cavern was shut in for five days. Nitrogen was then injected in the wells to depths of 28 to 83 feet below the casing seats. The well leak test was basically the same as the test described previously with two differences. (1) In this test, there was no hanging drill string in well 6 and this reauired lowering the interface logging tool directly into the nitrogen in the well. Each entry into the well required filling a lubricator (used for logging tool entry) with nitrogen from the well, and introduced the possibility of additional nitrogen leakage at the wellhead. (2) Nitrogen was injected into the wells with cavern brine pressure already at test pressure, whereas in the previous test, the nitrogen was injected before pressurizing the cavern and an adjustment of nitrogen-brine interface depth was made after the cavern was pressurized.

In the present test, after nitrogen was injected to the desired interface depth, periods of 43 to 49 hours were allowed for nitrogen temperature to approach, on a bulk basis, equilibrium with the borehole temperatures. At the end of this stabilization period, interface logs were run to measure reference interface depths. Seventy-one to ninety-five hours later, interface logs were repeated to determine movement from the reference depth. This movement was used to calculate nitrogen volume loss. Weight of nitrogen versus interface depth was measured during the initial injection to define borehole volume as a function of depth at pertinent depths. It is believed that nitrogen weight measurements during this test were more dependable than those during the previous test, primarily because measurement techniques were more developed.

Following the we.11 leak test, the nitrogen was bled from the wells and cavern pressure was reduced to 150 psi and the cavern was shut-in for about four days until the rate of pressure change with time appeared constant.

The portions of the test with the cavern filled with brine and shut-in at 450 psi and 150 psi were in addition to the cavern pressure and well leak tests, The purpose of these additional steps was to provide information which might lead to a better understanding of cavern creep, which is essential to determining a leak rate from pressure test results. The lower pressure of 150 psi is above but near the value required to duplicate casing seat pressure during quiescent oil storage at near zero brine head pressure.

Figure 14 is a graph of brine pressure in the cavern during the complete cavern pressure and well leak test. Pressure data of this figure are representative of all cavern 6 pressures measured with the exceptions of nitrogen pressures during the well leak test, and well 6 pressures which were at times influenced by oil being released from cavern roof traps and rising up into the well. The pressures will be discussed in considerable detail later.

Well Leak Test

Wellhead nitrogen and brine pressures obtained during the well leak portion of the test are shown on expanded scales in Figures 15 and 16. After the interface was initially set in well 6 at 612 hours, the pressure decayed for about 30 hours, possibly due to nitrogen temperature stabilization. Between the two interface measurements at 659 and 730 hours, pressure increased at a near constant rate. Pressure drops of about 1.5 psi are noted at the time of each interface measurement, due to loss of nitrogen when the well was vented to the lubricator to allow the logging instrument to enter the well. The drop in pressure at 734 hours following the second interface measurement was due to bleed off of nitrogen from wells 6B and 6C.

The rise in both nitrogen and brine pressure for wells 6B and 6C at 609 hours, Figures 15 and 16, is a result of charging well 6 with nitrogen. The rise in nitrogen pressure of well 6C and brine pressure of wells 6B and 6C before 596 hours is due to charging well 6B with nitrogen. The drop in nitrogen and brine pressure for well 6C at 709 hours was due to installation of a new set of instrumentation. Lightning had struck well 6C during an electrical storm a few hours earlier.

Interface depth measurements are presented in Table V. The times between the first and second interface measurements are considered to be temperature stabilization periods. Volumes lost between the second and third interface measurements were used for calculation of leak rates. In the calculations, volumes were normalized to constant pressure to eliminate the affect of nitrogen pressure change on volume. Volumes of the uncased portion of the wells, which were used in the volume loss calculations, were the same as described for the previous test for wells 6B and 6C. Workover operations on well 6 between the two tests affected the uncased portion of the well. Weights of nitrogen injected into well 6 together with interface depth measurements during charging of the well with nitrogen for this test indicated 0.0695 bbls/ft between 2744 and 2786 foot depths and 0.1432 bbls/ft between 2786 and 2820 foot depths. These well volumes were used in leak rate calculations for well 6. Results of the leak rate calculations are as follow:

Well	Leak Rate BBLS/Yr	Leak Rate From Previous Test BBLS/Yr
6	26	530*
6B	0	4
6C	236	2290

*Below casing seat

For well 6 the leak rate is 60-percent of the value calculated for the previous test when the nitrogen-brine interface is in the casing, a difference too small to be considered significant. It is more than an order of magnitude less than estimated values from the previous test with the interface below the casing seat. Although there was some question about the effect of nitrogen temperature stabilization in the calculations below the casing seat for the previous test, this difference is large enough to indicate a significant decrease in well leakage during this test. The only plausible explanation appears to be that some casing seat leaks were sealed by cement during attempts to set a plug in this well during well workover between the two tests.

For well 6C the leak rate is about an order of magnitude less than calculated for the previous test. During the previous test, there were indications of leaks at the 13 3/8" casing hanger at the wellhead. Between the two tests it was found that the hanger installation was not exactly correct and adjustments were made to correct it. Attempts to locate other casing and casing seat leaks between the two tests were unsuccessful. It thus appears that most of the leak of the previous test was at the hanger.

Experience during the workover of well 6 and 6C indicated the extreme difficulty of finding leaks of 200-300 bbls/yr (0.96-1.44 gal/hr) of nitrogen. The leak rate of a test fluid, such as saturated brine used during workover of wells 6 and 6C, would be a fraction of the nitrogen leak rate, and the fraction could be quite small depending on details of the leak. The previously determined leak in well 6 was not located and is presumed to have been sealed during attempts to set cement plugs below the casing seat during workover. The present leak in well 6C is of this same magnitude, is presumed to have existed since adjustment of the 13 3/8-inch hanger during workover, and could not be located. The well configuration, with the casing seat near the cavern roof and a relatively large open hole in the salt between the casing seat and cavern roof, made it appear doubtful that a competent cement plug could be set. During workover, tests of the cased portion of the well with one and two stage packers illustrated that packers frequently do not seal absolutely and there is no way to distinguish a packer leak from a well leak.

Since it appeared impractical to continue trying to locate and repair the relatively small leaks found in wells 6 and 6C at wellhead brine pressures of 490 psi, it was necesary to decide whether such leak rates should preclude use of the cavern for oil storage. A review of pressure drop equations[23] indicates that for turbulent flow through rough wall flow passages, volumetric loss rates of crude oil could be as high as about one-third the volumetric loss rates of nitrogen at 100 atmospheres pressures and 100°F. From this maximum, volumetric loss rates of crude oil decrease about 2 orders of magnitude for laminar flow. At the maximum ratio of one-third oil to nitrogen volumetric loss rate, the combined nitrogen leak rates of 26 bbls/yr from well 6 and 236 bbls/yr from well 6C would correspond to crude oil leaks which do not exceed the DOE criterion of 100 bbls/yr for a cavern at the test pressures.

A comparison of pressures at the wellheads and casing seats during the test with similar values during oil filled storage at maximum operating pressure (0.8 psi/ft to the shallowest casing seat) and at atmospheric wellhead brine pressure is presented in Table VI. It is noted in Table VI that wellhead pressures of 1100 psia at maximum operating pressure are 200 psi above the 900 psi limitation of the surface piping (piping is C-spec with maximum working pressure of 985 psi, and 900 psi is considered a realistic limit at the wellhead). Reduction of wellhead oil pressures by 200 psi would reduce wellhead brine pressure and casing seat pressures a corresponding amount. If this limitation is used to define maximum storage pressure, the casing seat pressures are closely approximated by the test values.

Hydraulic calculations by JDE for the current cavern well configurations have indicated the following maximum flow rates and pressure drops.

	Oil Flow Rate bbls/day	Pressure Drop In Oil Flow Passages (psi)	Pressure Drop In Brine Strings (psi)	Factor Limiting Flow
Maximum Oil Withdrawal Rate	172,000	340	102	23 ft/sec velocity in 7" casing of well 6
Maximum Oil Injection Rate (Cavern Empty)	172,000	340	91	23 ft/sec velocity in 7" casing of well 6
Maximum Oil Injection Rate (Cavern Empty)	160,000	298	81	900 psi limit on surface piping

During oil injection with the 900 psi surface piping limitation, pressure drops due to oil flow will reduce casing seat pressures below the test pressures. Although high transient wellhead oil pressures are normal during startup of oil withdrawal, design pressure in the oil line at the wellhead during withdrawal is 150 psi. With this wellhead pressure, well 6B casing seat pressure at maximum withdrawal rate is 1485 psia, nearly 400 psi below the test pressure. In summary, test pressures at the casing seat and wellhead were greater than any expected pressure during fill, storage and withdrawal. It was thus concluded that the measured well leaks represent an upper bound and should not preclude oil storage.

Cavern Shut in at Maximum Allowable Pressure

The cavern wells were filled with brine during this portion of the test, whereas during the comparable portion of the September 1980 test, the wells were filled to depths below the casing seats with oil. With brine filled wells, wellhead pressure corresponding to the maximum test gradient of 0.86 psi/ft to the shallowest casing seat would be about 875 psi. However, during the previous test, considerable oil was released from the cavern roof into the wells, causing an increase in wellhead pressure. To insure that pressures would not become excessive during this test, the maximum wellhead brine pressure was limited to 800 psia which was compatible with oil filled wells down to the cavern roof and was essentially the same as the previous test.

Wellhead brine pressures for this portion of the test are shown in Figure 17. There was an abrupt drop of about 3 psi in the well 6 pressure at 154 hours, attributed to a change of instrumentation. The rate of decay of well 6 pressure was less than that of the other wells. At about 190 hours, the pressure began to increase. The lower initial decay rate and the later change to a pressure increase is attributed to oil being released from the cavern roof and entering the borehole. Oil in well 6 was confirmed later in the test. Although a similar affect is possible on the annulus pressures of well 6B and 6C, it is much smaller if it does exist. No such affect is expected for the brine string pressures.

Brine string and annulus pressures of wells 6B and 6C continued to decay for the 8 1/2 day shut-in period. The decay rates decreased continuously with time and did not reach steady rates. Figure 18 is a graph of average pressure decay rate versus time. The rates for both brine string and annulus pressures of each well were obtained from linear regressions of pressures measured over 24 hour time periods. Except for the earliest three time periods, there are no significant differences between values for the four pressures, indicating no significant effect of oil entering the annuli of wells 6B and 6C. The 8 1/2 day shut in period was allowed in an effort to achieve a steady decay rate. The results of Figure 18 indicated several additional days might be required to achieve a steady decay rate. Since allowing these days would compromise subsequent portions of the test, the shut-in period was terminated.

Cavern Shut in at Maximum Operating Pressure

Wellhead brine pressure of 650 psia was used for this portion of the test. This corresponds to a pressure gradient of 0.80 psi/ft to the shallowest casing seat with oil filled wells. The five wellhead pressures for this portion of the test are shown in Figure 19.

It is noted in Figure 19 that the pressures in well 6 are considerably higher and increasing at a considerably higher rate than pressures of the other wells. This is attributed to a continuing release of oil into well 6. The brine string and annulus pressures of wells 6B and 6C all increase with time, compared with the decrease at the higher pressure. Seauential linear regressions covering 24 hour time periods indicate a near constant rate of pressure increase after 350 hours. Linear regressions covering the last 70 hours of shut-in for well 6B and 6C brine string and annulus data yield pressure increase rates of 0.17 to 0.26 psi/day, with an average value of 0.22 psi/day.

Cavern Shut in at 450 psia Pressure

During cavern depressurization from maximum operating pressure to 450 psia, volume bleed off and cavern pressure data were obtained. These data indicated a cavern elasticity of 57 bbls/psi, confirming results from previous tests. These were the only successful volume measurements during the June-July 1981 test.

Pressures measured during cavern shut in at 450 psi are shown in Figure 20. As previously noted, the pressure and pressure increase rate for well 6 is higher than for the other wells, presumably because of oil entering the borehole. Sequential linear regressions of well 6B and 6C wellhead pressures covering 24-hour time periods indicate a near constant rate of pressure increase after 520 hours. Linear regressions of the 43 hours of data after 520 hours for brine string and annulus data for these wells yield pressure increase rates of 2.02 to 2.09 psi/day, with an average value of 2.06 psi/day.

Immediately following the data discussed above with the cavern shut in at 450 psi, nitrogen was injected for the well leak test previously discussed. Prior to charging well 6 with nitrogen, 50 bbls total of oil with some brine were removed from well 6. The volume of 1305 feet of 7" casing is 50 bbls, and if this height of casing were filled with oil instead of brine, the pressure would be increased by 193 psi. At the beginning of oil removal, well 6 pressure was about 122 psi higher than well 6B brine pressure.

Cavern Shut in at 150 psia Pressure

Pressures measured with the cavern shut in at 150 psi are shown in Figure 21. During this phase of the test, surface piping was being connected to the wellheads in preparation for oil fill. This resulted in a considerable reduction of instrumentation which could be operated and a consequent reduction of data obtained.

Pressures for well 6 are still above those for wells 6B and 6C, though by a much smaller amount than previously because of the oil withdrawn before the well leak test. The reason for the abrupt change in rate of pressure increase for well 6 at 832 hours is not known.,

The data available for defining a steady rate of pressure increase at this condition is very limited. The data selected were the last 16 hours of data shown for well 6B and the last 24 hours of data shown for well 6C. The results of linear regressions of these data are pressure increase rates of 6.14 psi/day for well 6B and 6.22 psi/day for well 6C.

Summary of Pressure Change Rate Results

The measured rates of change of wellhead brine pressure at different cavern pressures are summarized in Figure 22. The figure includes results from all three tests both with the brine filled cavern and nitrogen filled wells. The figure shows a decreasing pressure change rate with increasing cavern pressure, as would be expected due to either salt creep or cavern leak.

Salt creep, the time dependent flow of salt under stressed conditions, will cause volume changes of underground salt storage caverns. Changing volumes correspond to changing pressures, therefore, evaluation of salt creep is essential to determine leak rate in terms of cavern pressure. Salt creep is a very complex and incompletely understood phenomenon. Finite element methods, as currently used for salt creep analyses of underground salt storage caverns, are generally considered to provide comparative relative results, but only order of magnitude results in an absolute sense. Factors affecting the accuracy of such analyses include typical relatively large variations in measured values of salt properties which must be used in the analyses, differences between the behavior of laboratory specimens and the insitu salt, the dependence of creep on salt temperature to about the ninth power, and the time dependent and stress history dependent nature of creep. Unfortunately, order of magnitude creep analyses are inadequate for analysis of cavern pressures to determine leak rate. It appears possible that in-situ measurements underway in caverns may, in the future, provide data, to improve the accuracy of creep calculations, possibly to the point where they would be useful for pressure test analysis.

Figure 22 indicates that at 625 psia wellhead pressure (maximum operating pressure), there was a 0.45 psi/day pressure increase rate during the June-July 1981 test, compared with a 0.98 psi/day pressure decrease rate during the September-October 1980 test[14]. The difference of 1.43 psi/day with a brine filled cavern elasticity of 57 bbls/psi, indicates a decrease in leak rate between the two tests of 29,800 bbls/yr at this pressure level. This very large improvement in indicated leak rate is surprising. The indicated improvement of well nitrogen leak rate between the two tests at 450 - 500 psia was an order of magnitude less than 29,800 bbls/yr, and brine leak rate is normally expected to be considerably less than nitrogen leak rate. It is certainly possible that a leak rate could increase more than an order of magnitude with an increase in wellhead pressure from 450-500 to 625 psia, in that leak rate is proportional to the difference between supply and discharge pressure to some power, and discharge pressure could be near supply pressure at the lower wellhead pressure. However, there is insufficient information to conclude this explanation is viable.

There are other apparent inconsistencies in the data of Figure 22 which have not been explained. The difference between data for brine filled cavern and for nitrogen filled well results of the June-July 1981 test is much larger than expected. The well leak test indicated a total nitrogen leakage of 262 bbls/yr, corresponding to a pressure decay rate of only 0.013 psi/day, whereas the difference in decay rate indicated by the figure is about 0.72 psi/day. This inconsistency is not due to a more elastic cavern with the nitrogen filled wells. Although nitrogen is much more compressible than brine, its effect on cavern elasticity is relatively small because of the relatively small volume, about 500 bbls compared with a cavern volume in excess of 8 million bbls.

Similarly, the difference between nitrogen filled well data from the January 1981 test and the June-July 1981 test is greater than expected. The difference in measured nitrogen well leak rate from the two tests of about 2600 bbls/yr corresponds to a pressure decay rate of 0.125 psi/day, whereas the difference indicated on the figure is about an order of magnitude higher. .

The most probable explanation for the discrepancies between measured pressure decay rates of the different tests (Figure 22) and between measured leak and pressure change rates is believed to be that at least some of the measured pressure change rates, which appeared near constant, were in fact still changing, and therefore, that the pressure change rate data of the Figure are not truly steady state values.

The results of Figure 22 are being used in attempts to get a correlation of finite element model analysis of cavern behavior with experimental results.

Effects of Cavern 6 Pressurization on Caverns 8 and 9 Pressures

Cavern 9 oil and brine pressures together with cavern 6 brine pressure during the pressurization of cavern 6 are shown in Figure 23. Each period of increasing pressure in cavern 6 is accompanied by a decrease in both oil and brine pressure in well 9. This is the same result indicated in Figure 13 from data obtained during the January 1981 well leak test, and as previously mentioned, is considered a positive indication of the absence of fluid communication between caverns 6 and 9.

Cavern 8 oil and brine pressure together with cavern 6 brine pressures during pressurization of cavern 6 are shown in Figure 24. There is an increase in pressure in cavern 8 during and following the first phase of pressurization of cavern 6. This was explained by a partially open valve at well 8 which allowed oil flow into cavern 8 when oil was being pumped into cavern 7. After 40 hours, there is no clear effect of cavern 6 pressurization on cavern 8 pressures.

Cavern 7 Pressures

Brine for pressurization of cavern 6 was obtained from cavern 7 during the injection of oil into cavern 7. Pressures in cavern 7 during and following the oil fill are shown in Figure 25. The sawtooth pressure profiles result from intermittent flow of oil into cavern 7. It was necessary to backflush the cavern 7 brine string at times because of salt buildup and a resulting increase in cavern pressures during oil injection. There is no clear indication that the varying pressures in cavern 7 had any effect on pressures in caverns 6, 8, or 9. Following the completion of oil fill, cavern 7 was shut-in and pressure instrumentation was left on cavern 7 for about 7 1/2 days. As a matter of record, linear regressions of 5 days of pressure data toward the end of this shut-in period indicated a brine pressure increase rate of 1.75 psi/day and an oil pressure increase rate of 1.94 psi/day.

SUMMARY DISCUSSION

During the cavern brine pressure test of September-October 1980[14], a cavern pressure decay rate of 0.98 $\pm$ 0.12 psi/day was measured at a maximum operating pressure gradient of 0.8 psi/ft. Calculations of the effects of measured cavern brine temperature and salinity change rate indicated the thermal and solutioning effects could explain a net pressure decay rate of about 0.06 to 0.15 psi/day. The remaining pressure decay rate of 0.71 to 1.04 psi/day was attributed to a combination of salt creep and leakage. It was not possible to separate these two effects. If it is assumed that there is no effect of salt creep and that the unexplained pressure decay rate is due only to leakage, the leak rate would be 14,800 to 21,600 bbls/yr. If salt creep is in the normally expected direction to cause cavern closure, it would cause a pressure increase and the resulting indicated leak rate would be correspondingly higher.

Because of the inability to separate the effects of leak and creep, and therefore the inability to determine total cavern leak rate from a conventional pressure test, a well leak test was devised to measure leak rates of nitrogen from the wells alone. The logic of the test was that the most probably points of leaks in an entire cavern are in the vicinity of wells where the competent salt has been breached, and therefore, that well leak rates are probably total cavern leak rates. This logic is subject to serious question in cases where the cavern is near another cavern or the edge of the salt dome.

A well leak test was made in January 1981 which indicated two of the three cavern 6 wells were leaking, well 6 at a rate of over 500 bbls/yr of nitrogen and well 6C at a rate of over 2000 bbls/yr. The test was limited to a wellhead brine pressure of 450 psi because of maximum allowable wellhead pressure' of 2000 psi. The leaks were considered serious enough to warrant well workovers.

Following workover of wells 6 and 6C, the brine pressure test and well leak test were repeated in June-July 1981. The well leak test indicated that at a slightly higher wellhead brine pressure of 490 psi, leak rates of these two wells were about an order of magnitude lower than in the previous test: 26 bbls/yr for well 6 and 236 bbls/yr for well 6C. A reduction in cavern leak rate between the September 1980 brine pressure test and the June-July 1981 well leak and brine pressure test is confirmed by a change from a cavern pressure decay rate of 0.98 psi/day during the first test to a cavern pressure increase rate of 0.22 psi/day during the latter test, both at maximum operating pressure.

Generally speaking, the most probable location of leakage from a cavern is from the wells, where the competent salt has been breached. However, there is a possibility of leakage from the cavern proper. If such leakage does exist, the probahility is high that it will be to a nearby cavern or a nearby edge of dome. In the case of salt domes where extensive gas is present, a possible leakage path would be to caprock through a zone of gas bearing impurities in the salt. Such a leakage path appears unlikely for the subject cavern since the salt in the West Hackberry salt dome has been found to be essentially free of gas.

To examine the possibility of communication between caverns, pressures in nearby caverns 7, 8, and 9 were monitored during the pressurization of cavern 6. Pressures in the nearest cavern, 9, which has a minimum separation of about 225 feet (Figure 3), indicated a definite absence of fluid communication. Pressures in cavern 8, which is considerably further away, did not indicate fluid communication. Oil was being injected into cavern 7 during pressurization of cavern 6, influencing cavern 7 pressures to the extent that any affects of communication were masked. However, fluid communication between caverns 6 and 7 or 8 appears less likely than between caverns 6 and 9 because of their considerably greater separation. Similarly, fluid communication between cavern 6 and edge of dome appears less likely than between caverns 6 and 9 because of the large separation of about 500 feet[24]. Based on the above, it appears probable that the only leaks from cavern 6 are from the wells.

In addition to concerns regarding cavern leakage, a major concern is the structural integrity of the cavern. Sonar surveys have indicated the cavern has a near flat roof with unsupported roof spans from 1100 to 1240 feet, depending on the direction of the survey. The unsupported spans are roughly four times maximum cavern diameter chosen for the expansion caverns and the flat roof shape is undesireable from a structural standpoint. In spite of these highly undesirable features, there is strong evidence indicating the cavern has structural integrity. It survived depressurization to oil head pressure during the September 1978 accident with no apparent structural damage. This depressurization was probably the most severe stress loading condition the cavern has experienced since the beginning of its formation. Also, it represents the most severe condition the cavern is likely to experience during its use as an oil storage cavern. In addition to this strong experimental verification of structural integrity, structural analyses of the cavern using finite element model computer codes "MARC," "ADINA78" and "SANCHO" have indicated no structural problems, that is, no condition where stresses in the salt closely approach a tensile condition. Reference 25 includes analyses of an instantaneous depressurization of the cavern from brine head to oil head pressure, a simulation of the effects of loss of portions of the cavern roof due to slabbing, a two year creep response in the immediate vicinity of the cavern, and the elastic response of the cavern during a certification pressurization cycle. Appendix A begins with an elastic solution during depressurization of the cavern void from lithostatic pressure to an oil filled condition with brine head pressure. It then proceeds through stress and creep calculations over a 30-year time period. The analysis indicates minimum compressive stresses of 250,000 psf immediately following depressurization, being reduced only to 197,000 psf at the end of 30 years. The analysis further indicates maximum shear stress immediately following depressurization of only 113,000 psf and that these stresses are relieved by creep as time progresses. A reduction in cavern volume of 22-percent over the 30-year period is indicated. As stated earlier, the absolute value of creep closure is questionable. Efforts including field measurements at several oil filled caverns are underway to attempt to validate the creep model.

CONCLUSIONS

Although all questions cannot be conclusively eliminated, it is believed that cavern 6 is suitable for long-term oil storage.

1. The most probably location of a cavern leak is from the vicinity of the entry wells. Well leak tests during the June-July 1981 test indicated combined oil leakage from the three entry wells would be well within the DOE leak rate criterion of 100 bbls/yr per cavern at the most severe design operating conditions of the cavern.

2. It was not possible to determine conclusively, due the undefined effects of creep closure of the cavern, that there was not leakage from the cavern other than from the wells. However, it is highly probably that any such leakage would be to a nearby cavern or to the edge of the dome. Pressure measurements during the test on cavern 9,

the nearest cavern about 225 feet away, gave a positive indication of no fluid communication between caverns 6 and 9. Pressure measurements on caverns 7 and 8 indicated neither communication with cavern 6 or a positive absence of communication. However, because they are considerably further away than cavern 9, over 400 feet compared with about 225 feet, communication with cavern 6 is much less likely. Further; leakage to the edge of the dome. located about 500 feet away, should under normal conditions be far less likely than leakage to cavern 9.

3. It is believed that serious structural failure of the cavern is unlikely during long-term oil storage at normal pressures (near brine head), or during accidental depressurization to oil head pressures. There is no indication of structural problems as a result of the accidental depressurization of the cavern to oil head pressures in September 1978. Analyses indicate the cavern is structurally adequate, and there were no indications of abnormal roof motion or slabbing during the test.

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TABLE1

WEST HACKBERRY CAVERN 6 WELL LOGS

Well No.	Log Date	Log Name	Logging Company	Logged Depths (Ft.) Top	Bottom
6	6/4/77	CBL	MG	0	2640
	7/22/77	CBL	DA	0	2596
	4/30/80	Casing Insp.	McC	0	2600
	4/30/80	Collar	McC	0	2612
	5/3/80	CDL/GR/CAL	Sch	0	3260
	5/3/80	BGT	Sch	2600	3260
	5/4/80	Temperature	MG	0	2640
	5/10/80	BGT	Sch	2430	2602"
	5/12/80	BGT	Sch	2550	2663
	5/12/80	SP/CAL/IND	Sch	2530	2842
	5/12/80	Temp.	Sch	32	3410*
	5/22/80	GR/Neutron	MG	0	3274"
	5/22/80	Density	MG	0	2938*
	5/23/80	CBL	MC	0	2620*
	5/23/80	Directional	ss	0	2580
	5/27/80	CNL/CDL/GR/CAL	GO	1900	3270
6 Note 1	7/17/80	CAL	Sch	2603	3260
	7/29/80	TDT	Sch	2560	2715
	7/30/80	Density	MG	2200	2730
	8/3/80	Collar	GO	0	2724
	8/16/80	Temperature	Sch	50	2705
	8/19/80	CBL	W	0	2748

	8/20/80	GR	McC	0	2810*
	8/20/80	Casing Insp.	McC	0	2810"
	9/12/80	CBL	MG	0	2730*
	9/13/80	CAL	MG	2600	2939
	9/18/80	Directional	ss	0	3364*
	9/25/80	Temperature	GO	0	3380*
	9/25/80	Temperature	GO	6	2799
	9/26/80	Interface	MG	2800	3010
	10/8/80	Interface	MG	2800	3100
6A	8/25/78	SP	Sch	100	1480
	9/5/78	Direction	Sch	102	1625
	9/5/78	BGT	Sch	102	1625
	9/19/78	BGT	Sch	1601	2247
6B	7/10/78	CBL	West	200	2610
	7/14/78	Collar	West	0	3360
	3/17/80	BGT	Go	18	3300*
	3/20/80	CBL/GR/Collar	GO	32	2604*
	3/20/80	CNL/CDL/GR/CAL	GO	2573	3208*
	3/20/80	GR/Sonic	GO	2440	3266*
	3/20/80	Temperature	Go	1 3	3392
	3/21/80	Casing Insp.	McC	0	2576
	3/22/80	Casing Insp.	DL	0	2580
	9/12/80	Temperature	GO	0	3394*
	9/15/80	Interface	MG	2400	3390
	9/16/80	Interface	MG	2500	3390
	10/1/80	Interface	MG	2500	3390
	10/9/80	Noise	GO	3385	3385*

	10/10/80	Interface	MG	2500	3386
6C	7/8/78	BGT	Sch	96	1717
	7/8/78	Direction	Sch	96	1717
	7/25/78	SP .	Sch	1717	3178
	7/25/78	BGT	Sch	1717	3179
	7/31/78	CBL/Collar	Sch	230	3192
	3/14/80	Temperature	GO	0	3400
	3/15/80	CBL/GR/Collar	GO	40	3200*
	3/15/80	CDL/GR/CAL	Go	3058	3310*
	3/17/80	BGT	Go	18	3252"
	3/22/80	Casing Insp.	DL	0	3160
	3/24/80	Casing Insp.	McC	0	3175
	9/13/80	Temperature	GO	0	3380*
	9/16/&l	Interface	MG	3100	3380

Note 1. Logged during and after the last workover on well 6 per Ref. 9..

*A copy of log is included in Reference 14.

TABLE II

COMMENTS ON LOGS

Well 6B

BGT 3/17/80	Shows a hole diameter of over 20" at 2585 ft. with rugged hole down to 2700 ft. The hole is reasonably smooth from 2700 to 3150 ft. where it begins to increase in size. At 3210 ft. the diameter exceeds 20 inches.
CBL 3/20/80	Shows an excellent bond from 2570 ft. to 2030 ft. and fair to excellent bond from 2030 to 420 ft. The log shows an erratic bond below 2570 ft.
CNL/CDL/GR/CAL 3/20/80	Shows $2.14 < \rho < 2.44$ from 2670 ft. to 3190 ft. Above 2670 ft. the density plot is erratic, probably due to the casing cement. There is one spike of $\rho = 2.85$ at 3116 ft. The neutron porosity and the gamma plots have little character.
Sonic 3/20/80	The sonic log shows a very consistent 68 to 70 micro sec./ft. from 2590 to 3190 ft. Below 3190 ft. the plot is somewhat erratic. The high density indication at 3116 ft. is not reflected on the sonic or the gamma ray logs.
Temperature 9/12/80	Shows a steady increase from surface temperature to 123.4^{o}F at 2740 ft. then decreases. Bottom hole temperature is 101.6^{o}F at 3390 ft.
Noise 10/9/80	The noise log does not show any major acoustical disturbances in the cavern.

Well 6C

CBL 3/15/80	Shows an excellent bond from 2450' to 3166' and fair to excellent bond above 2450'.
CDL/GR 3/15/80	Shows $2.1 < \rho < 2.33$ with GR peaks up to 70 API units.
BGT 3/17/80	Shows a hole diameter about 14" with a minor washout at 3175'.
Temperature 9/13/80	Shows a steady increase from surface temperature to 111.7^{o}F at 2330 ft. then decreases. Bottom of cavern temperature is 101.6^{o}F at 3400 ft.

Well 6 - Prior to 7" Casing Installation

BGT 5/10/80	Shows a significant increase in hole diameter immediately below the casing.
Temperature 5/12/80	Shows a steady increase from surface temperature to 124.4°F at 2550 ft. then decreases. There is 'a one degree step increase at 3390 ft. and a bottom of cavern temperature of 101.8°F at 3450 ft.
GR/Neutron 5/22/80	Shows the changes in apparent porosity at the cavern roof (3216'), the 12 3/4" casing seat (2629'), and the 9 5/8" casing seat (2595'). Shows a porosity anomaly at 2020' and at 2350'.
Density 5/22/80	Shows the casing seat locations.
CBL 5/23/80	Shows excellent bond from 2620' to 2015' and poor bond above 1850 ft. Shows a bond anomaly zone from 2015' to 1920 ft.

These logs and other evidence indicated that it would be desirable to install a 7" casing thru the existing 9 5/8" casing seat.

Well 6 - After 7" Casing Installation

GR 8/20/80	Shows correlation on depth of the gamma increase below 2650 ft. and below 1400 ft.
Casing Insp. 8/20/80	Verification of casing inside diameter and collar locations of 7" casing.
CBL 9/12/80	Shows excellent cement bond from 2730 ft. to 2630 ft. The bond above 2630 ft. is fair to poor and erratic. Reference 9 indicates significant problems during the cementing operations.
Directional 9/18/80	Shows a deviation of 103 ft. at a depth of 3196 ft. and a maximum dog leg at 2896 ft.
Temperature 9/25/80	Shows a steady increase from surface temperature to 118.4°F at 2670 ft. then decreases to 101.8°F at 3380 ft.

TABLE III

ABBREVIATIONS AND SYMBOLS

BGT	Borehole Geometry Tool
CAL	'Caliper
CBL	Casing Bond Log
CDL	Compensated Density Log
CNL	Compensated Neutron Log
DA	Dresser Atlas
DL	Dia-Log Company
GO	GO Wireline
GR	Gamma Ray
IND	Induction
McC	McCoullough
MG	Micro Gage, Inc.
Sonic	Acoustic Velocity Log
Sch	Schlumberger Well Services
SP	Spontaneous Potential
SS	Sperry-Sun, Inc.
SWS	Side Wall Samples
TDT	Thermal Neutron Decay Time
W	Welex
West	Western Wireline Service
ρ	Density gm/cm^3

TABLE IV

NITROGEN BRINE INTERFACE MOVEMENTS

DURING JANUARY 1981 TEST

We 11	Hours*	Log Value of Interface Depth (ft)	Log Value of Casing Seat Depth (ft)
6	48.	2782	
	171.5	2736	2743
	292.5	2715	
6B	51.5	2658	
	167.5	2660	2579
	264.5	2660	
6C	71.75	3204	
	169.5	3186	3161
	263.5	3163	
	288.5	could not locate	

*Elapsed time since beginning of test at 10:30 on 1/12/81

TABLE V

NITROGEN BRINE INTERFACE MOVEMENTS

DURING JUNE-JULY 1981 TEST

Well	Hours*	Log Value of Interface Depth, ft	Log Value of Casing Seat Depth, ft
6	612.75	2818	
	658.75	2803	2735
	730.0	2796	
6B	596.5	2660	
	639.5	2660	2583
	733.5	2658	
6C	588.5	3190	
	637.5	3189	3162
	732.0	3186	

*Elapsed time since beginning of test at 23:00 on June 5, 1981

TABLE VI

CASING SEAT AND WELLHEAD PRESSURES (PSIA) AT

DIFFERENT CAVERN OPERATING CONDITIONS

Condition	Wellhead Brine Pressure	Well 6 Casing Seat Pressure	Well 6 Wellhead Pressure	Well 6C Casing Seat Pressure	Well 6C Wellhead Pressure	Well 6B Casing Seat Pressure	Well 6B Wellhead Pressure
Nitrogen Well Leak Test	490	1950	1790	2150	1940	1870	1715
Oil Filled[d] Cavern-Storage at Maximum Operating Pressure[c]	625[a]	2140	1100[a]	2300	1100[a]	2080	1100[a]
Oil Filled[d] Cavern-Storage at Atmospheric Wellhead Brine Pressure	15[a]	1530	490[a]	1690	490[a]	1470	490[a]

a - Value for no flow into or out of the cavern

c - Gradient of 0.8 psi/ft of depth to the shallowest casing seat, well 6B at depth of 2580 feet

d - To depth of longest string, 3374 ft in well 6C

Note: Oil Specific gravity 0.876

APPENDIX A

Structural Analysis of Creep Eehavior

West Hackberry Cavern 6

M. H. Gubbels

A creep analysis was undertaken of West Hackberry Cavern No. 6. This analysis was accomplished usinq the finite element code SANCHO. The elastic properties used were average properties for laboratory tests of West Hackberry salt while the creep properties modeled were those secondary creep properties found in table 4, Section III of Reference Al. The stress exponent used was 4.9 and was derived from the same data as the table.

The analysis assumes WH Cavern No. 6 is an axisymmetric void of the average dimensions (1160 ft. max. roof dia.) of the 1980 sonar survey. This void is modeled in a large cylindrical block (2400 ft. high by 3600 ft. diameter) of salt to which pressures representing lithostatic loading are applied. Gravity loading and the in-situ stress state are also simulated. Internal pressurization of the cavern is that of an oil filled cavern under brine head pressure.

Figure A-l shows the analysis axisysmmetric half section at a time of zero days. This is the elastic solution of the cavern analysis when the pressure is lowered from lithostatic to brine head. The roof deflects .34 ft. downward while the cavern floor moves upward about .20 ft. Figure A-2 shows the maximum stress or the resolved stress developed that is closest to being tensile at time zero. The least negative (compressive) stress developed is essentially the cavern brine pressurization stress of 250,000 psf. The salt is far from failing in tension. Figure A-3 shows the maximum shearing stress developed at time zero, it being 113,000 psf. (784 psi) and in the region of the maximum cavern radial dimension, the pancake edge region. This shear stress is not high compared to the failure shear stress of laboratory specimens, 3,700 psi for unconfined specimens. As will be seen this calculated shear stress is greatest in magnitude at time zero and is relieved by creep as time progreses.

Figure A-4 shows the vertical displacement of the cavern at time equal to 11,000 days (30 years). The maximum downward displacement takes place at the cavern roof centerline and amounts to approximately 11 ft. while the upward motion of the floor is 4.4 ft. Whereas the movements are substantial, they do not indicate catastrophic failure. Figures A-5 and A-6 show the maximum stress and maximum shear stress for the same 30-year time. The largest maximum stress occurs in the salt about 300 ft. above the cavern roof but a -197,000 psf is still substantially compressive. The maximum shear stress has actually been relieved in the high stress areas. Hence the salt near the pancake extremity area is further from failure at 30 years than earlier in time. Creep has redistributed the stress and smoothed the high stress areas.

The total calculated change in volume for 11,000 days is 22.5%. The brine outflow rate in barrels/day versus days is shown in Figure A-7. Because of limited data and the state of development of the creep model used, the absolute value of creep closure is questionable. Field measurements are underway to provide data to validate the creep model.

References

Al. Whiting, G. H., "Strategic Petroleum Reserve (SPR) Geological Site Characterization Report West Hackberry Salt Domes," Sandia National Laboratories, SAND80-7131, October 1980.

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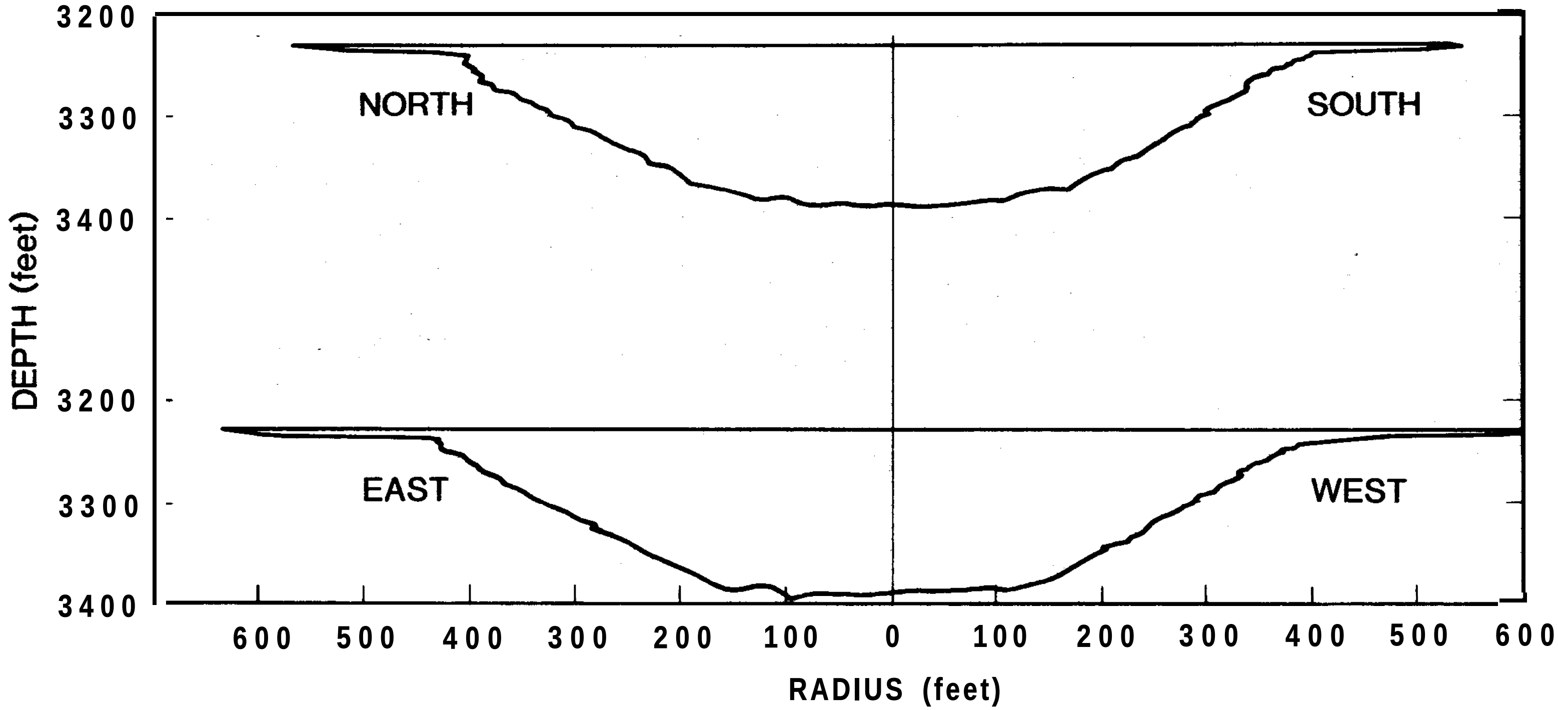


FIGURE 1 - VERTICAL SECTIONS OF CAVERN FROM SONAR SURVEY THROUGH WELL 6

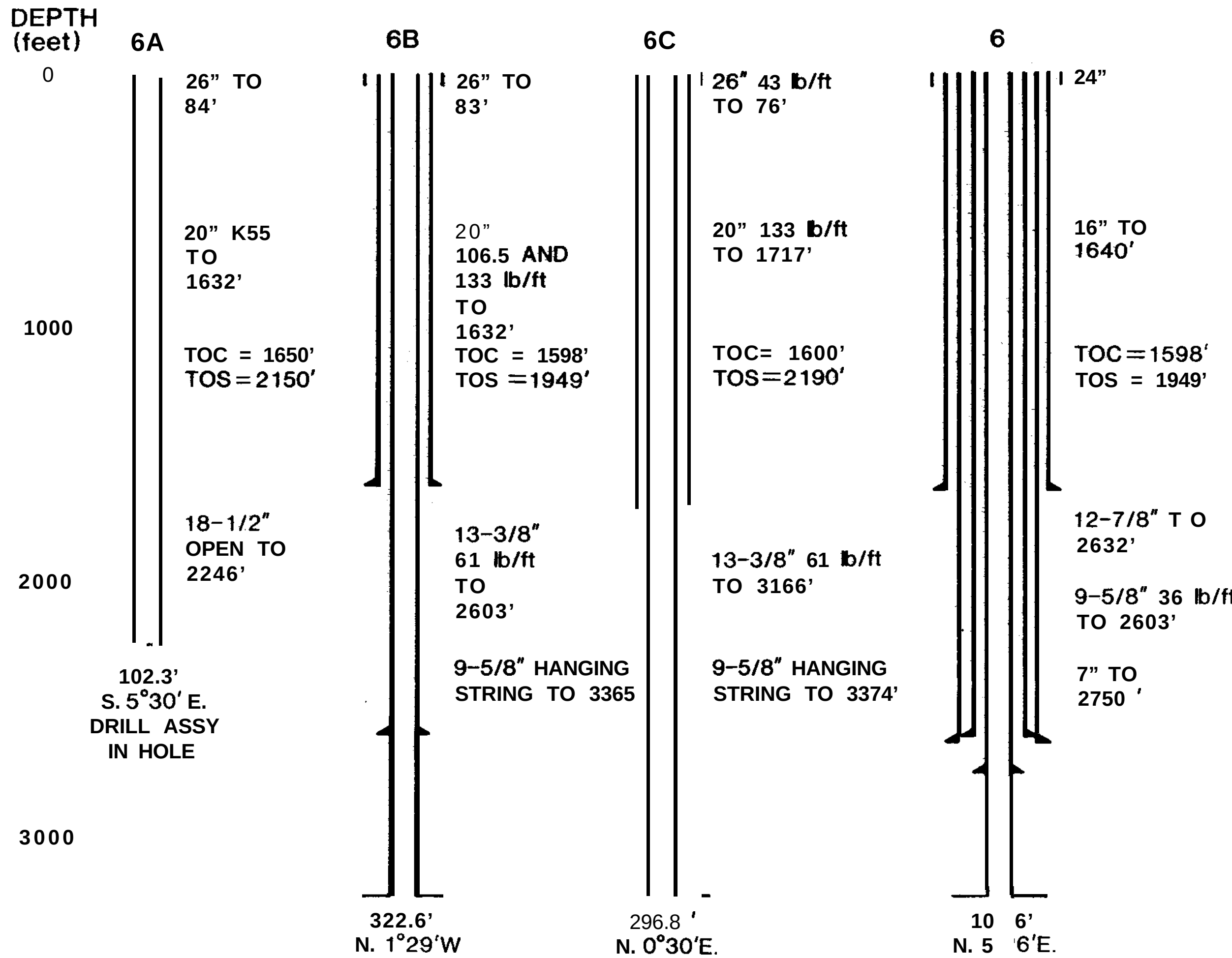
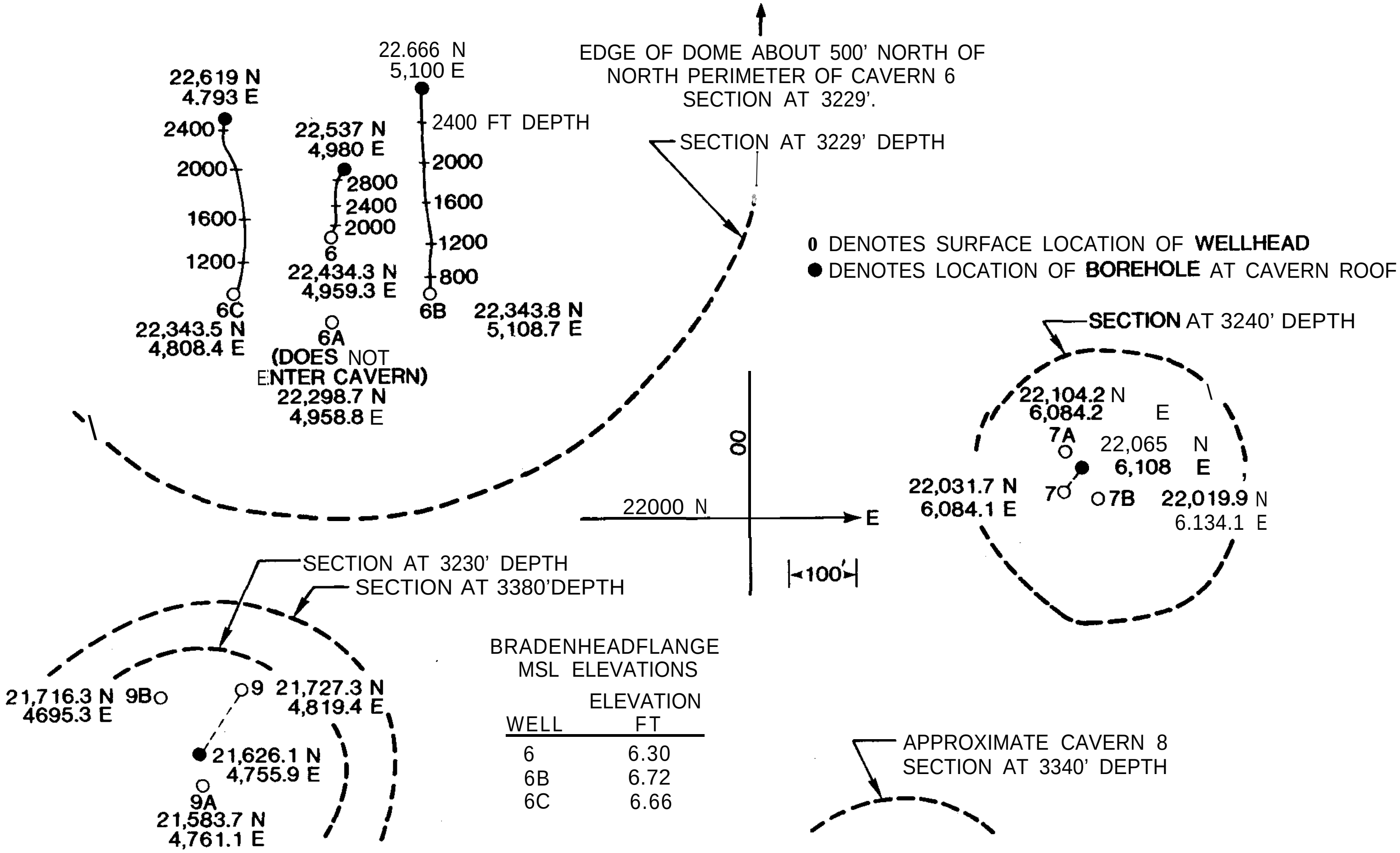


FIGURE: 2 - CAVERN WELL CONFIGURATIONS



BRADENHEADFLANGE
MSL ELEVATIONS

WELL	ELEVATION FT
6	6.30
6B	6.72
6C	6.66

FIGURE 3 - WELL LOCATIONS AND RELATION OF CAVERN 6 TO ADJACENT CAVERNS

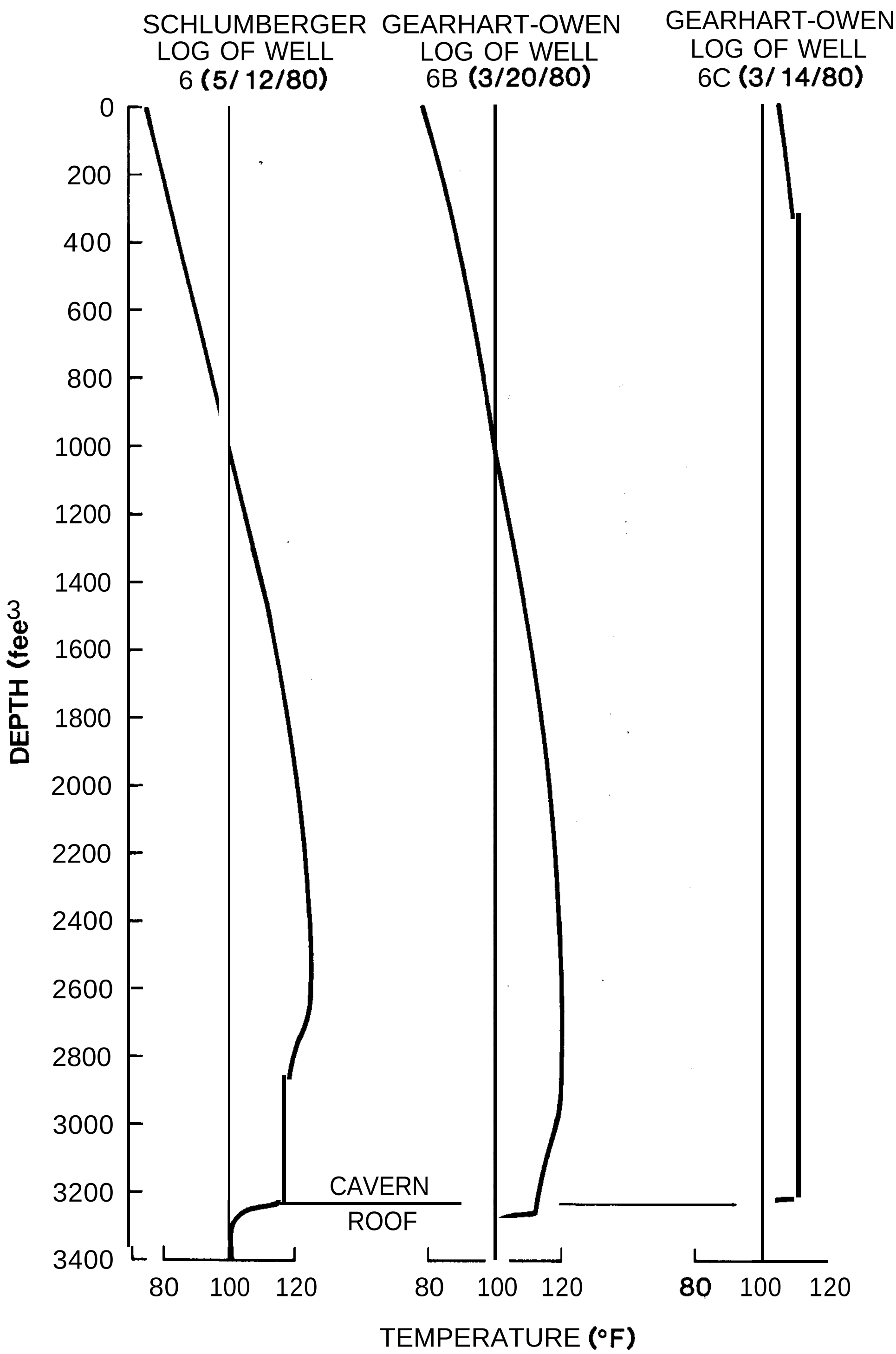


FIGURE 4 - WELL TEMPERATURES FROM LOGS

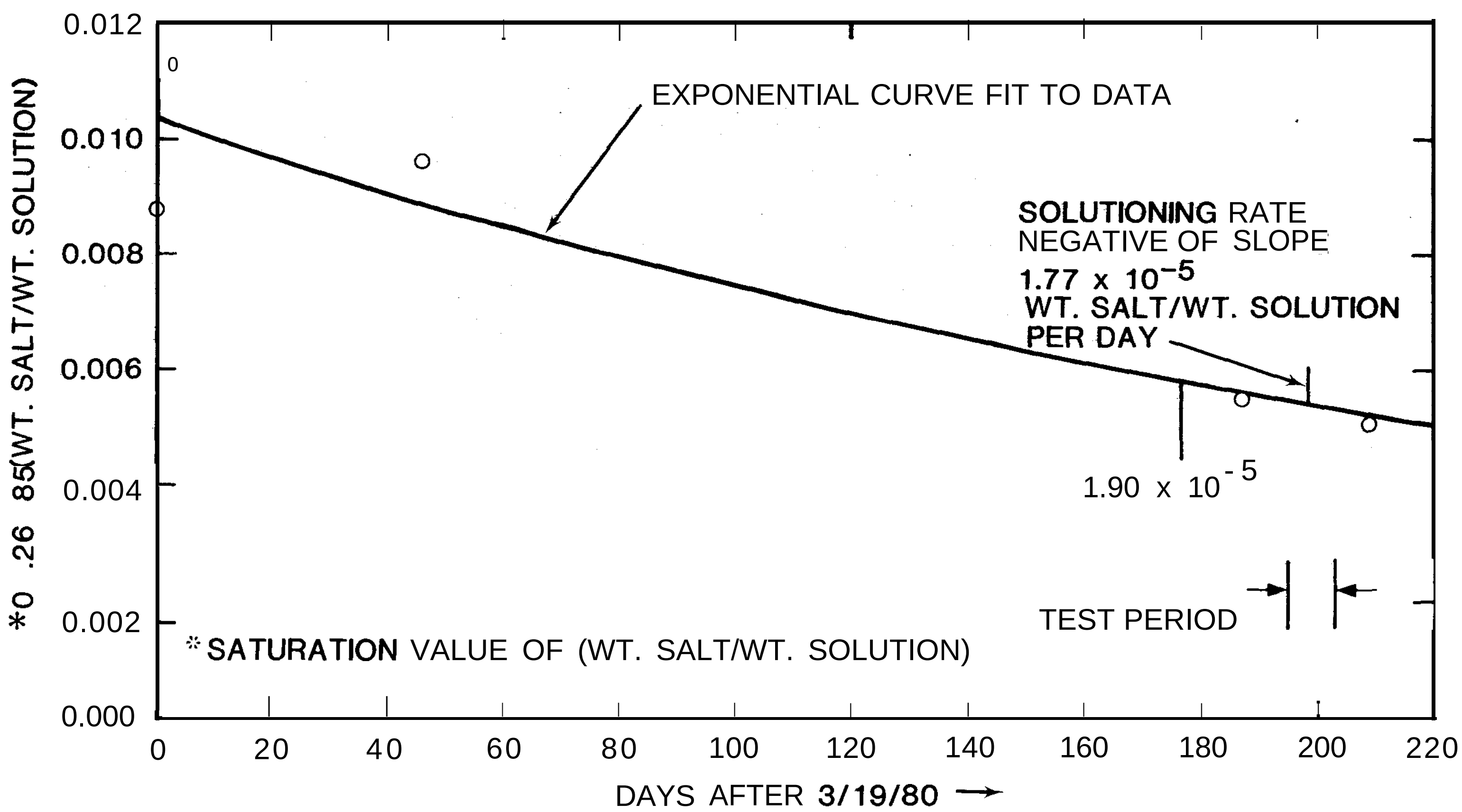


FIGURE 5 - CAVERN BRINE SALINITY VARIATION WITH TIME

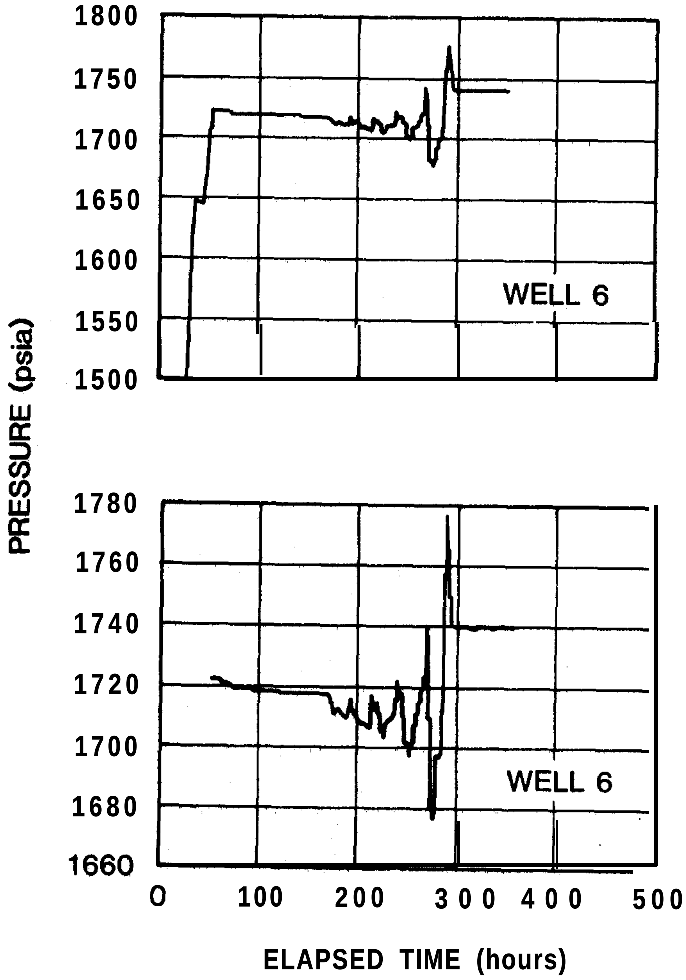


FIGURE 6 - NITROGEN PRESSURE AT WELLHEAD OF WELL 6, FIRST PROBE
(LOWER GRAPH IS ON AN EXPANDED SCALE)

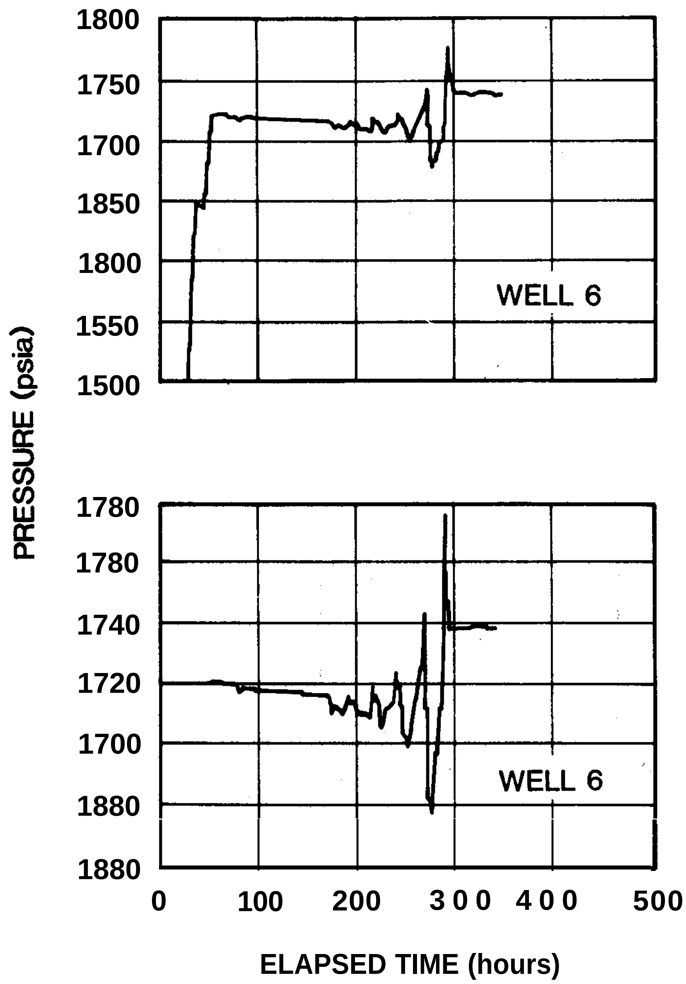


FIGURE 7 - NITROGEN PRESSURE AT WELLHEAD OF WELL 6, SECOND PROBE
(LOWER GRAPH IS ON AN EXPANDED SCALE)

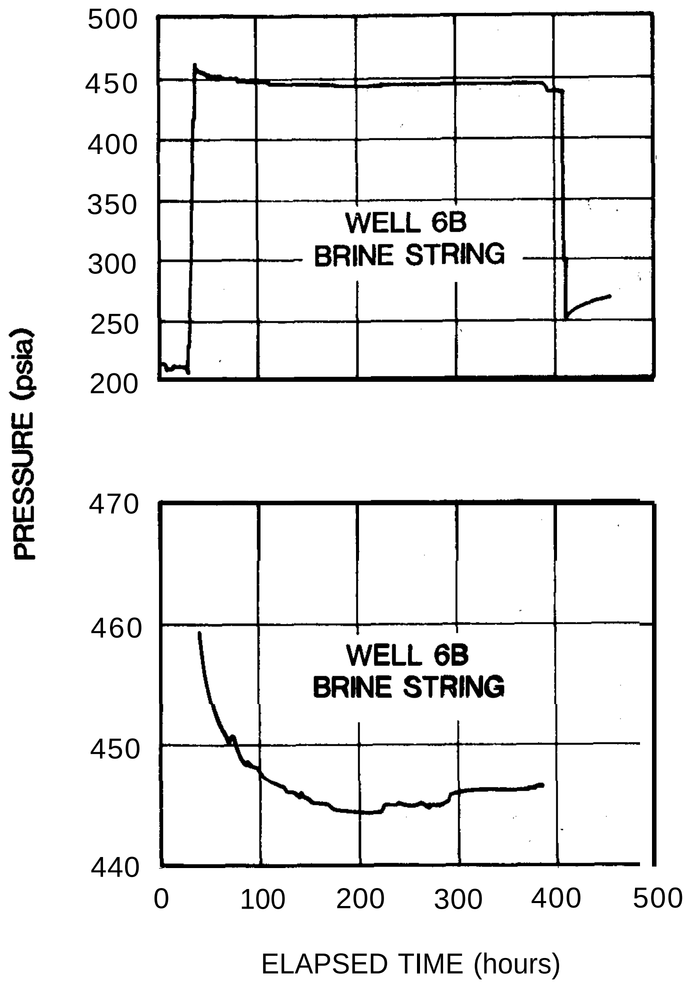


FIGURE 8 - BRINE PRESSURE AT WELLHEAD OF WELL 6B
(LOWER GRAPH IS ON AN EXPANDED SCALE)

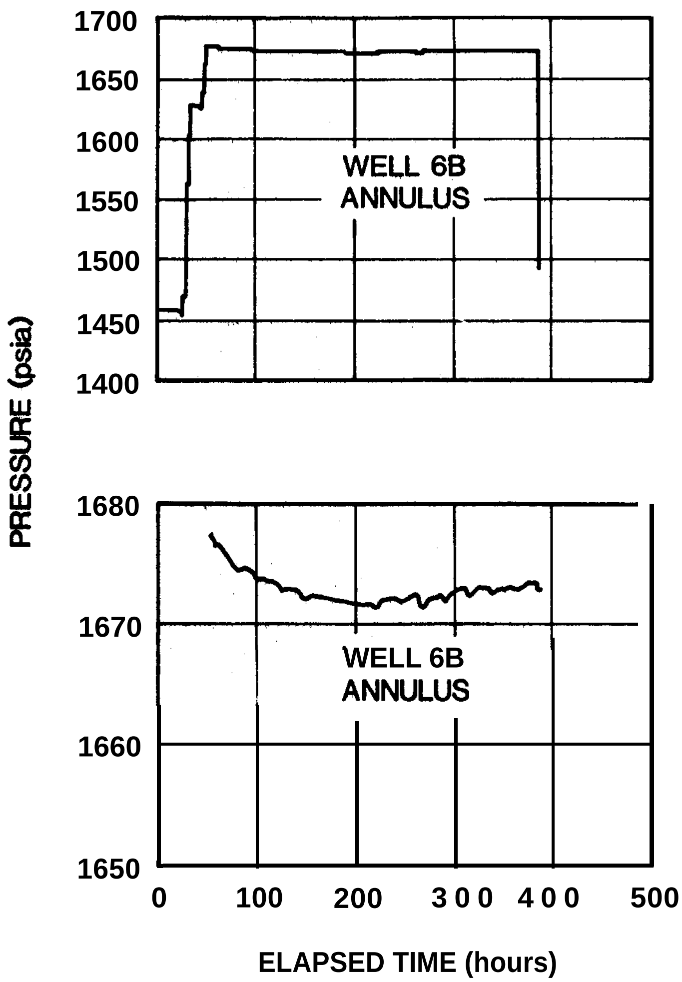


FIGURE 9 - NITROGEN PRESSURE AT WELLHEAD OF WELL 6B
(LOWER GRAPH IS ON AN EXPANDED SCALE)

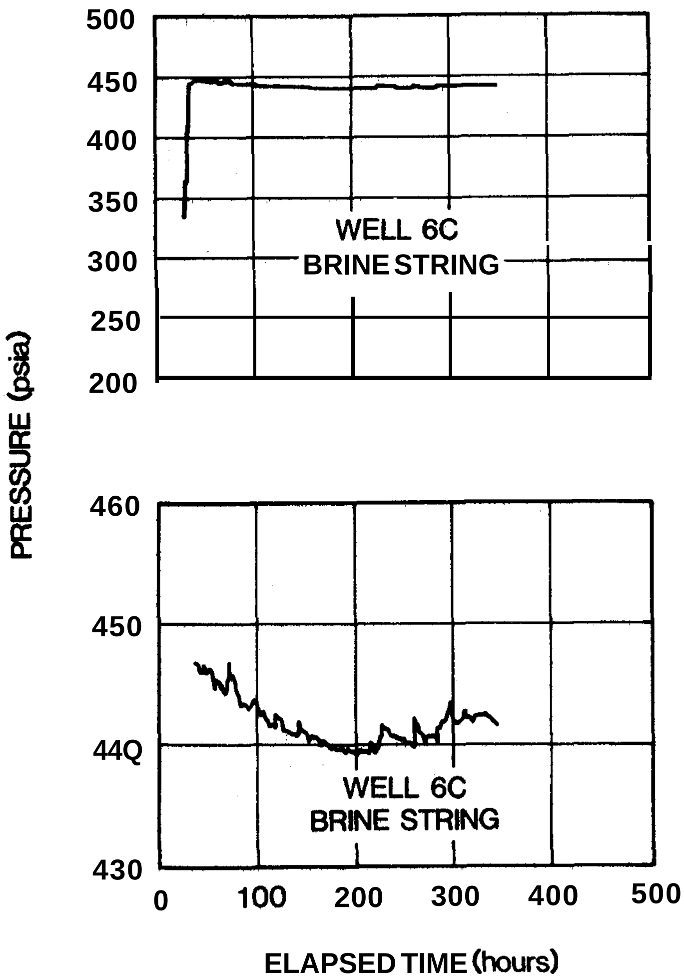


FIGURE 10 - BRINE PRESSURE AT WELLHEAD OF WELL 6C
(LOWER GRAPH IS ON AN EXPANDED SCALE)

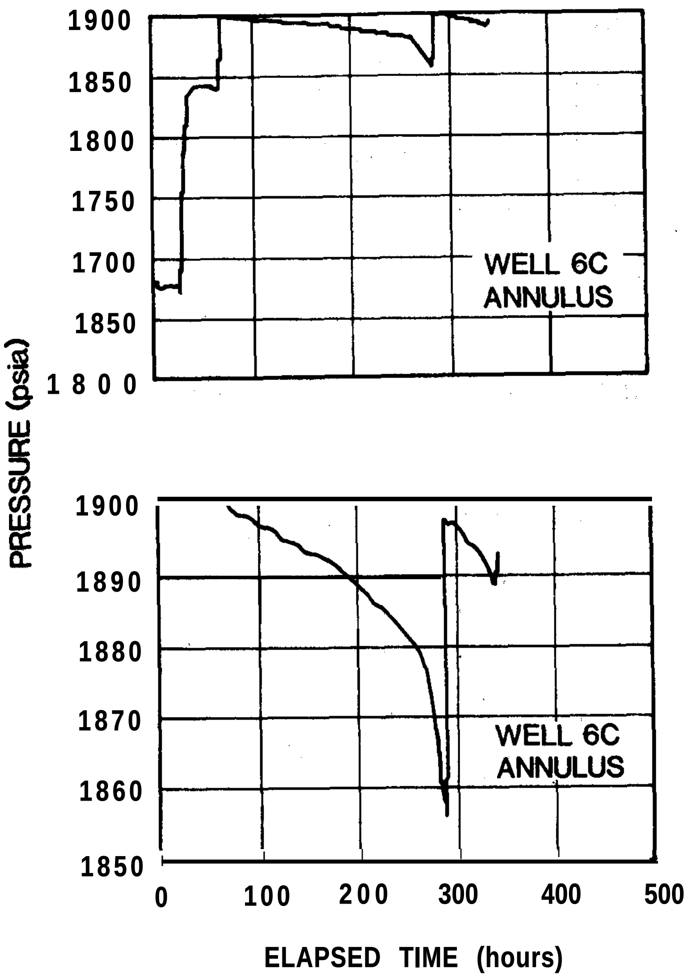


FIGURE 11 - NITROGEN PRESSURE AT WELLHEAD OF WELL 6C
(LOWER GRAPH IS ON AN EXPANDED SCALE]

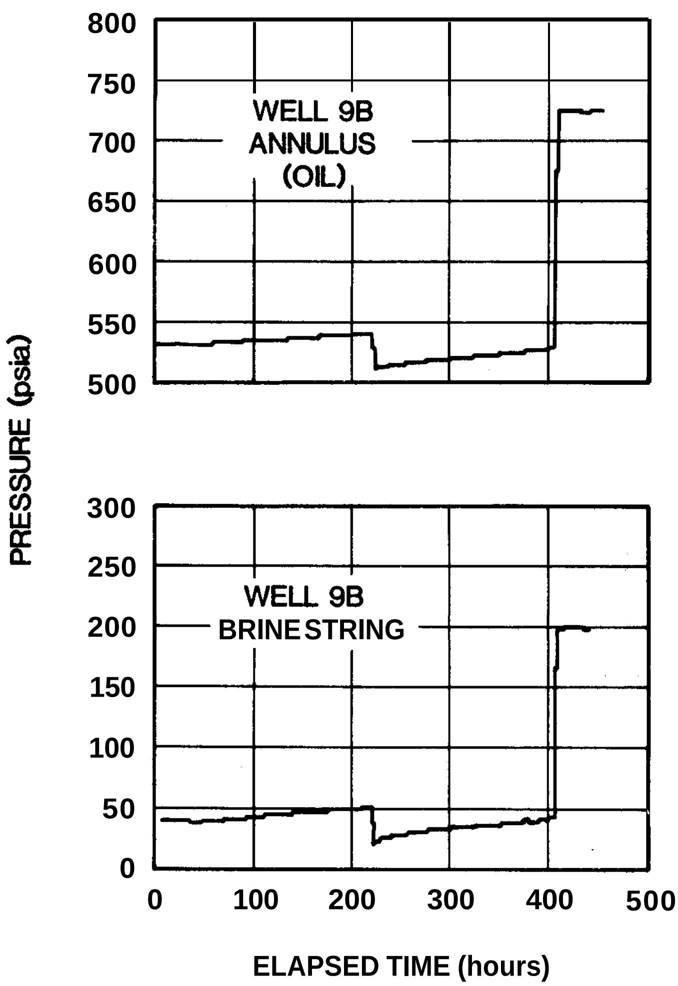


FIGURE 12 - BRINE AND OIL PRESSURE AT WELLHEAD OF WELL 9B

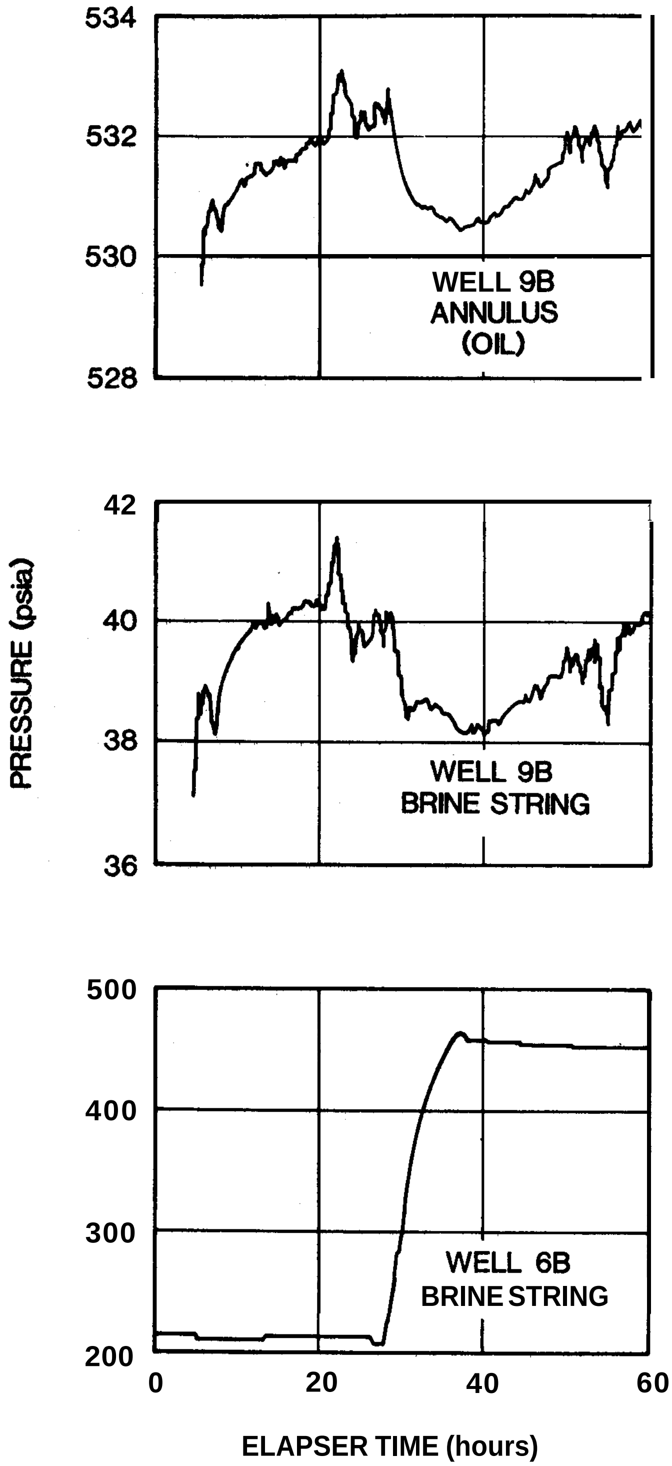


FIGURE 13 - EFFECT OF CAVERN 6 PRESSURIZATION ON CAVERN 9 PRESSURE

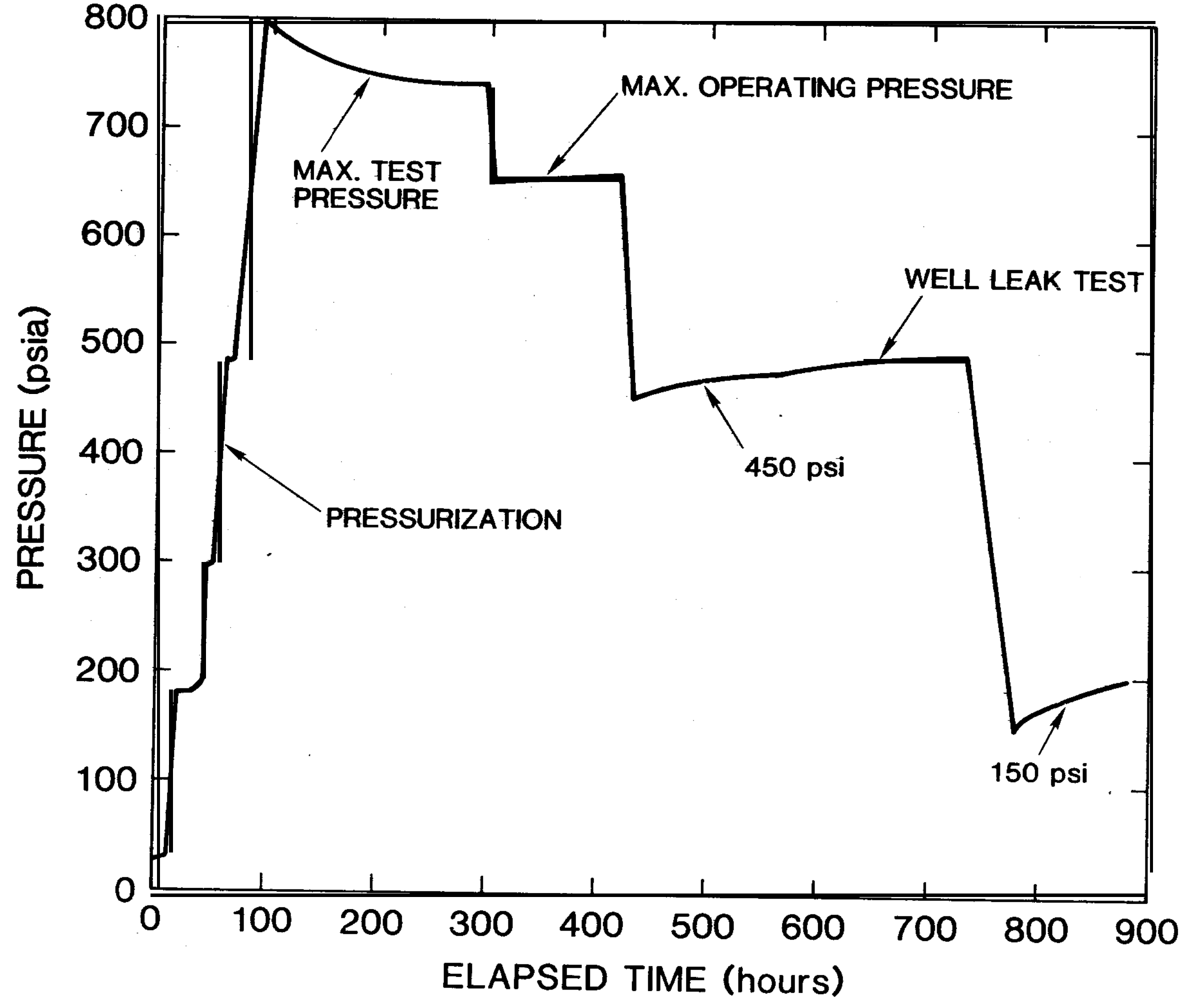


FIGURE 14 - WELL 6B BRINE PRESSURE PROFILE DURING JUNE-JULY 1981 TEST

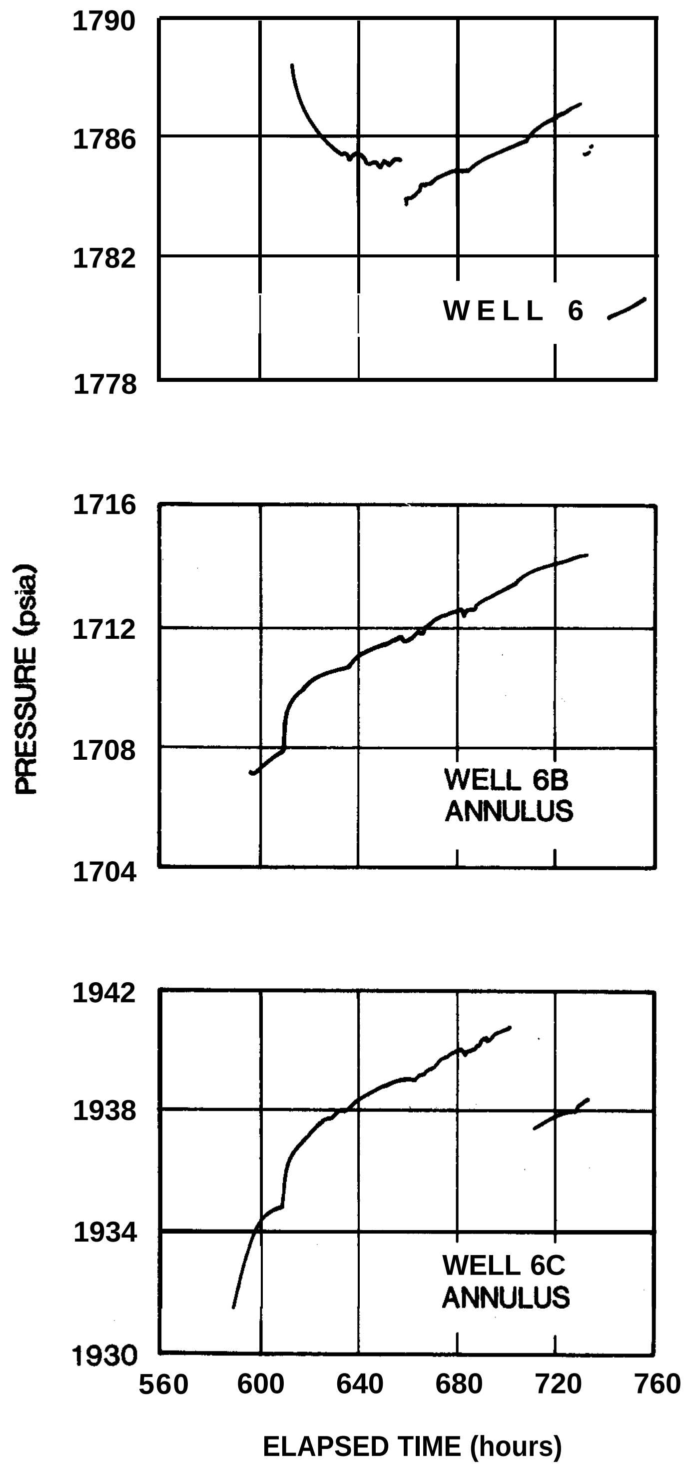


FIGURE 15 – NITROGEN PRESSURES AT WELLHEADS DURING SECOND WELL LEAK TEST

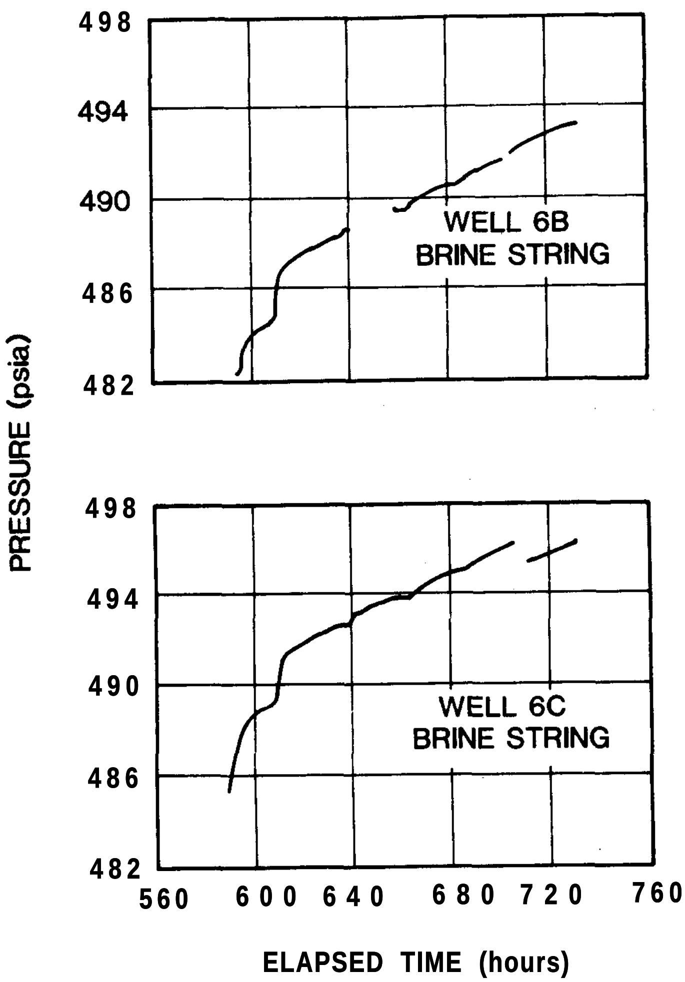


FIGURE 16 - BRINE PRESSURES AT WELLHEADS DURING SECOND WELL LEAK TEST

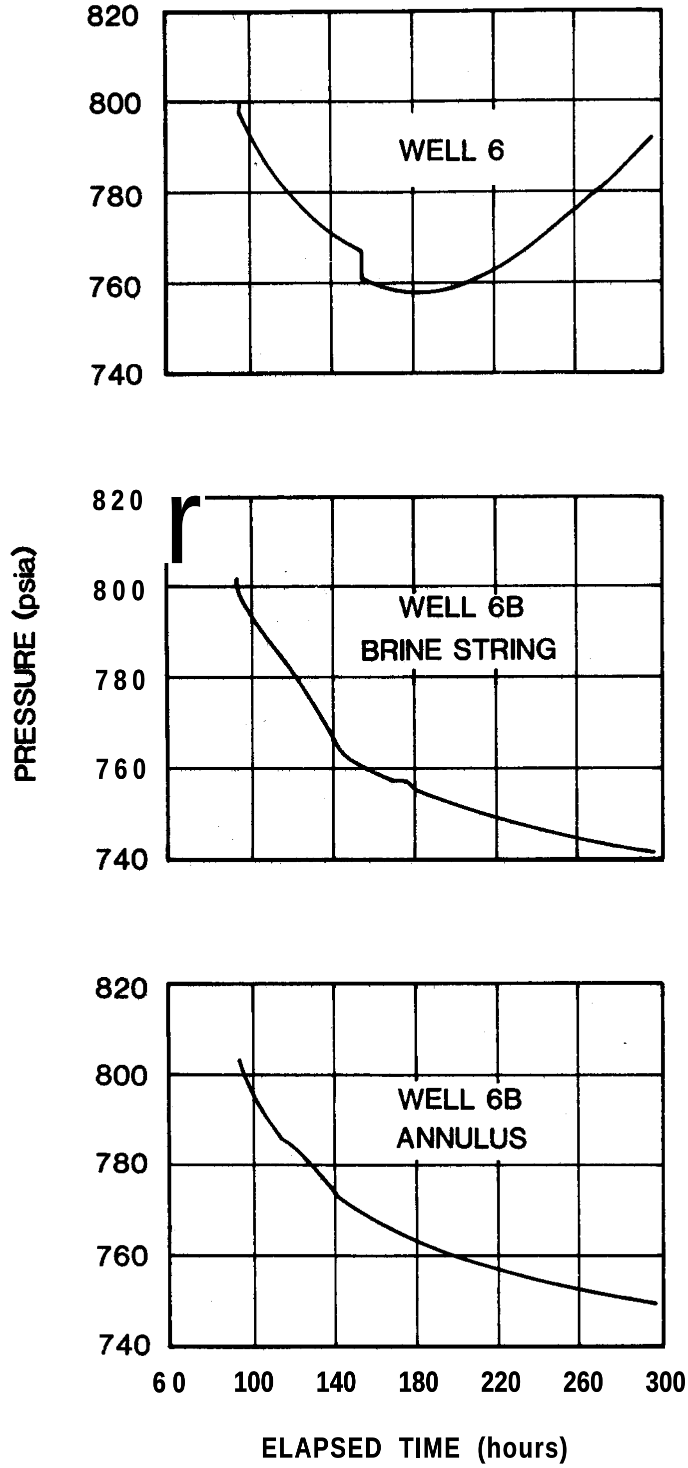


FIGURE 17 - WELLHEAD BRINE PRESSURES FOLLOWING CAVERN SHUT IN AT MAXIMUM ALLOWABLE PRESSURE

a. WELLS 6 AND 6B

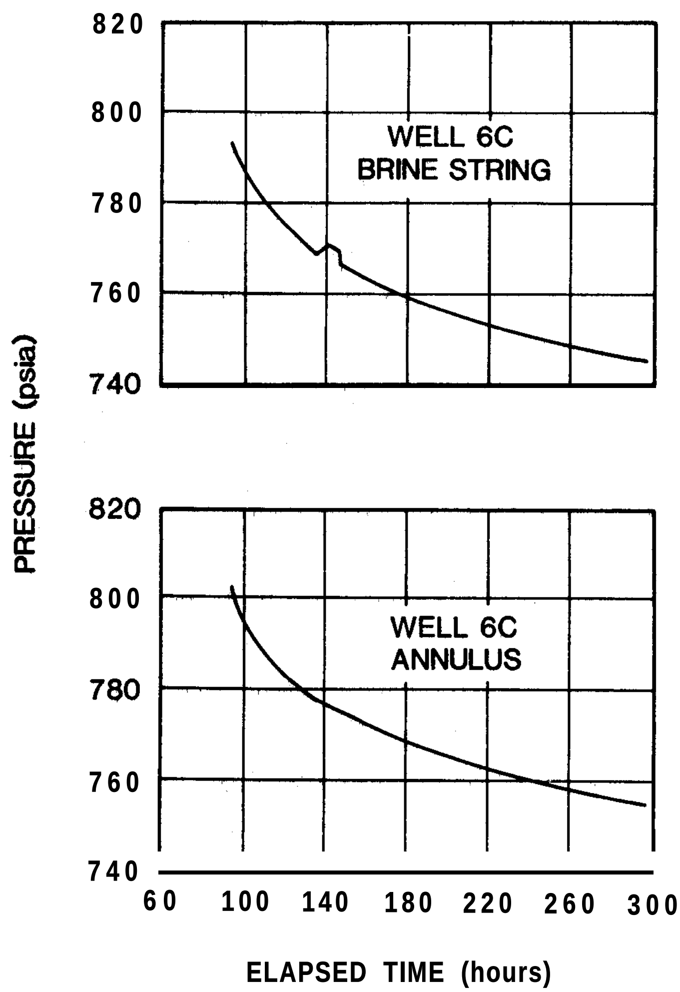


FIGURE 17 – CONCLUDED

b. WELL 6C

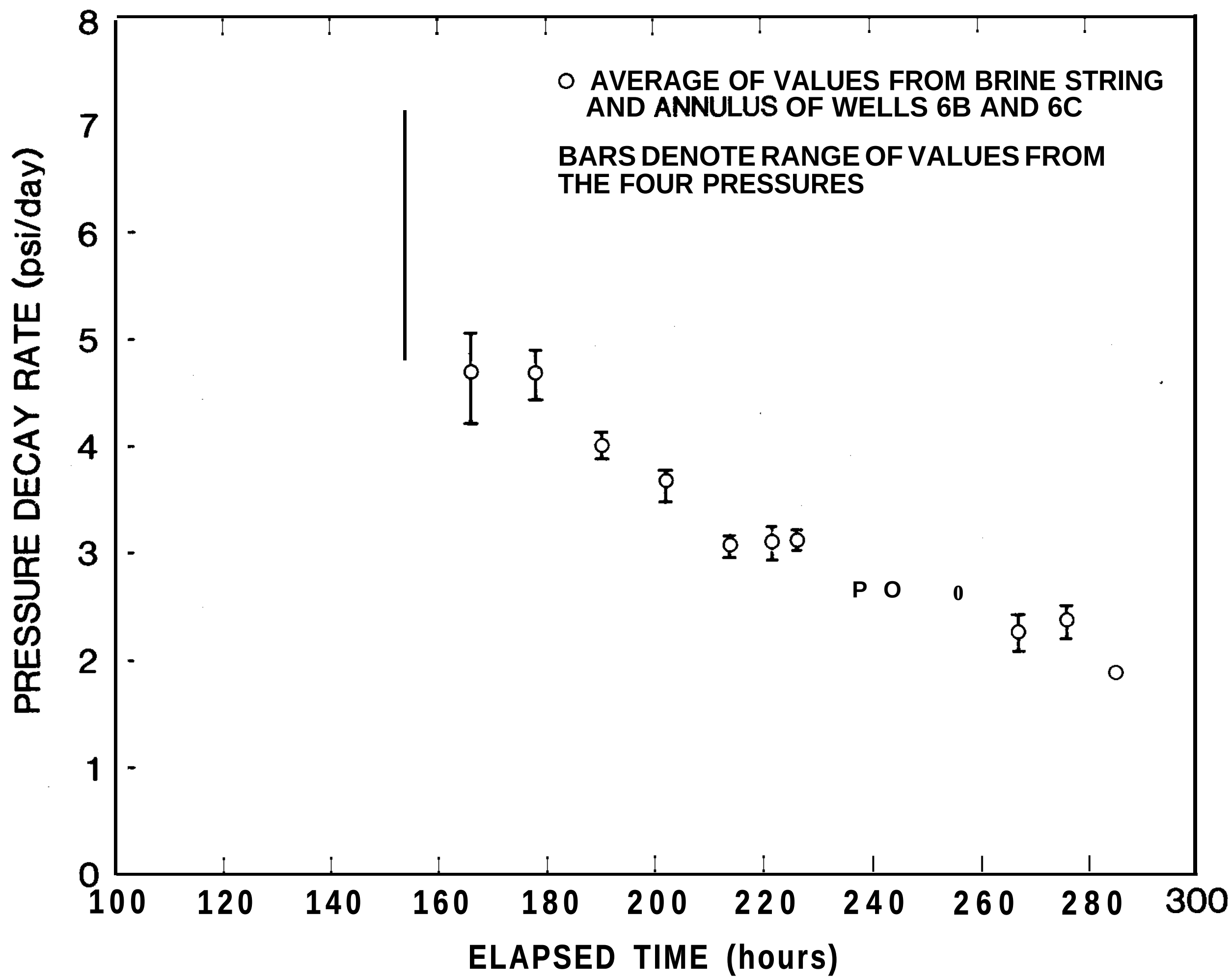


FIGURE 18 - AVERAGE PRESSURE DECAY RATES DURING CAVERN SHUT IN AT MAXIMUM ALLOWABLE PRESSURE

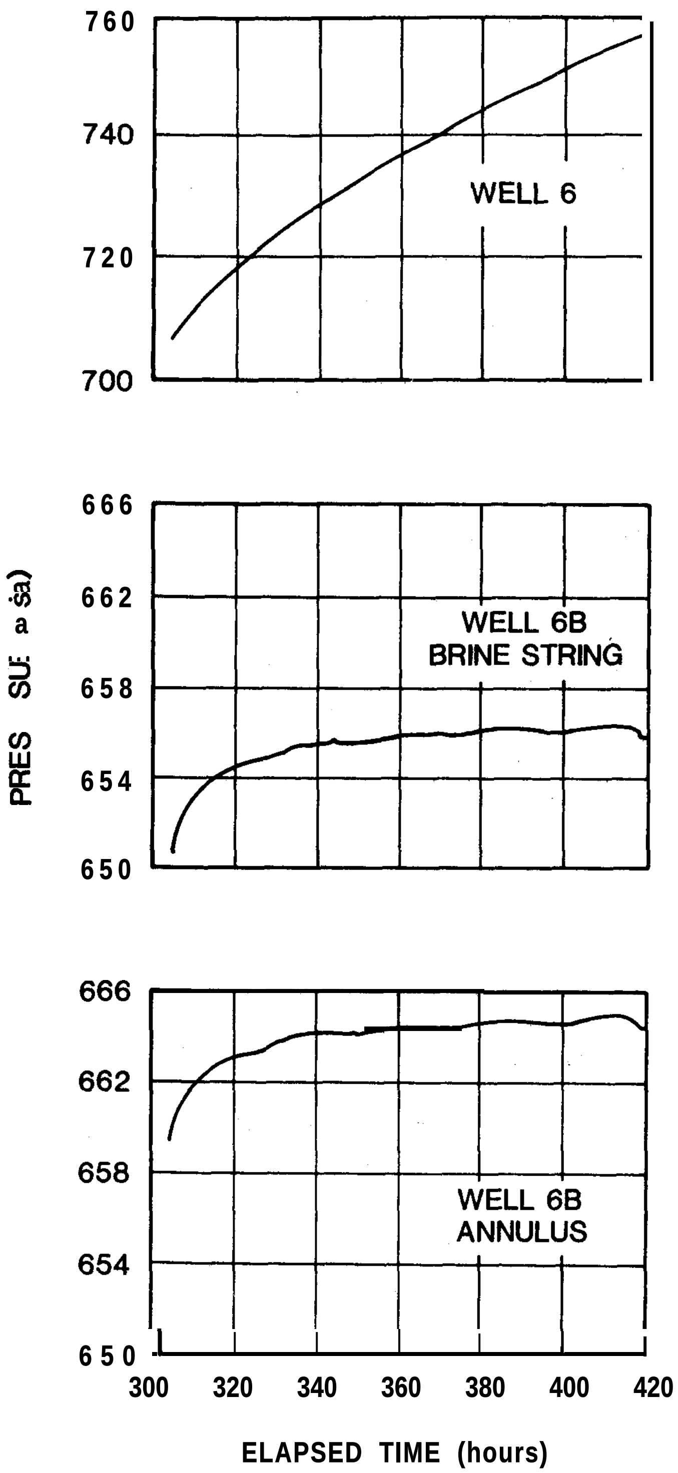


FIGURE 19 - WELLHEAD BRINE PRESSURES FOLLOWING CAVERN SHUT IN AT MAXIMUM OPERATING PRESSURE

a. WELLS 6 AND 6B

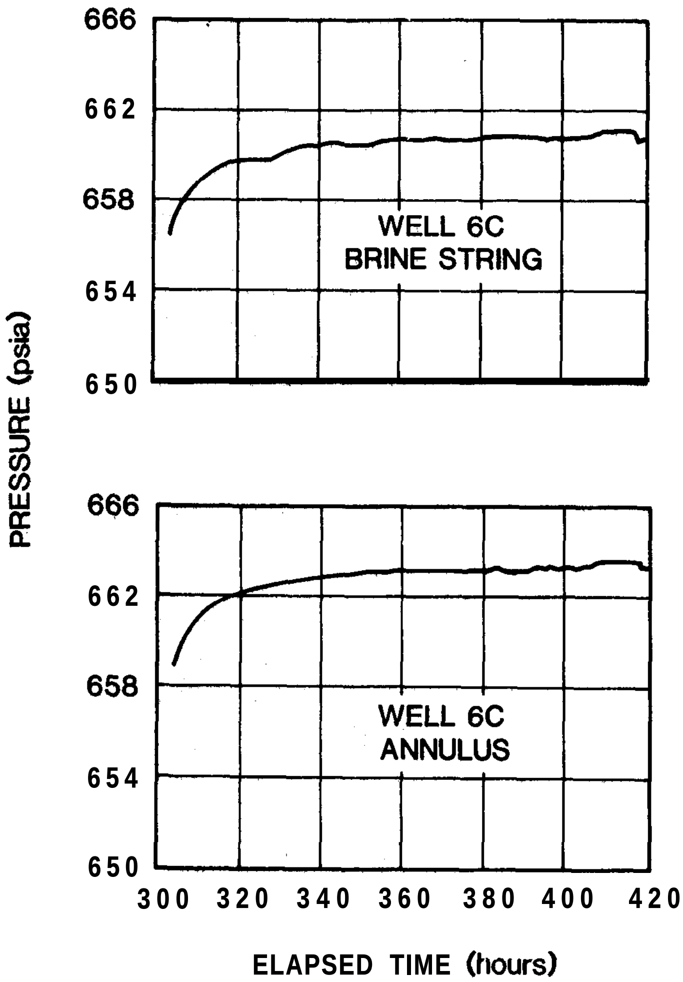


FIGURE 19 - CONCLUDED

b. WELL 6C

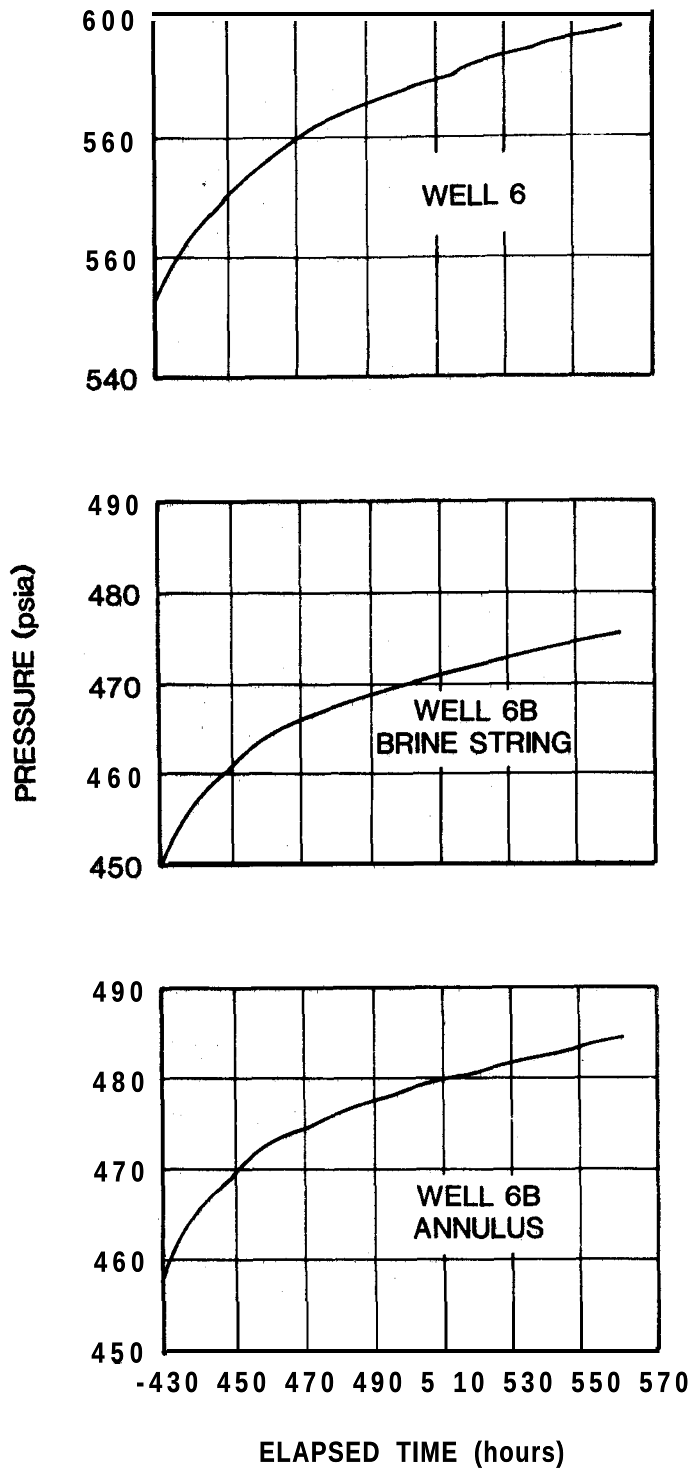


FIGURE 20 - WELLHEAD BRINE PRESSURES FOLLOWING CAVERN SHUT IN AT PRESSURE OF 450 PSIA

a. WELLS 6 AND 6B

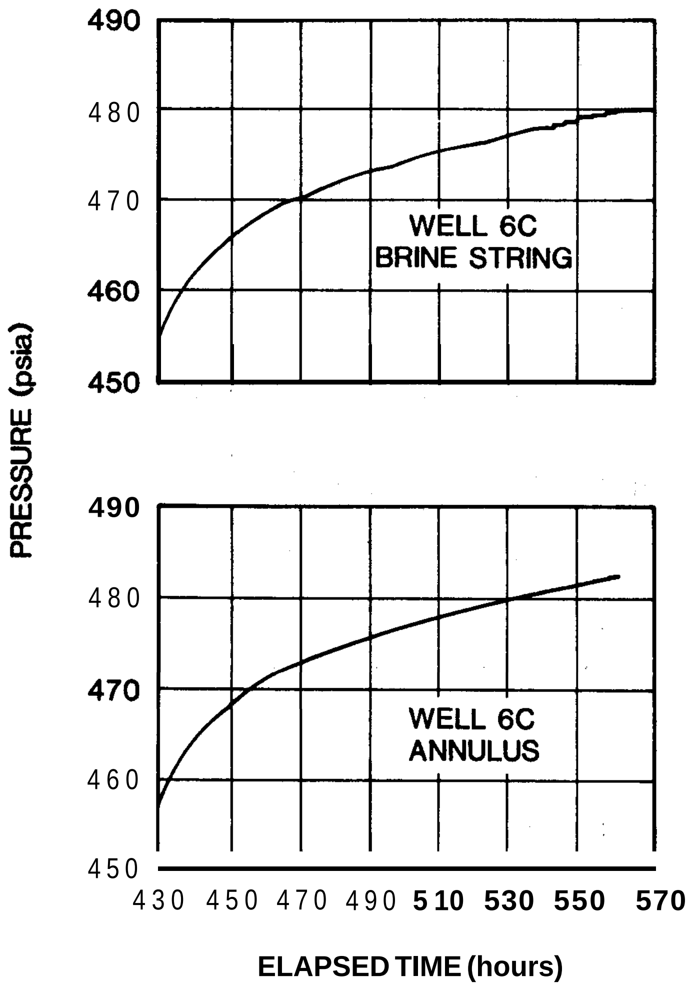


FIGURE 20 - CONCLUDED

h. WELL 6C

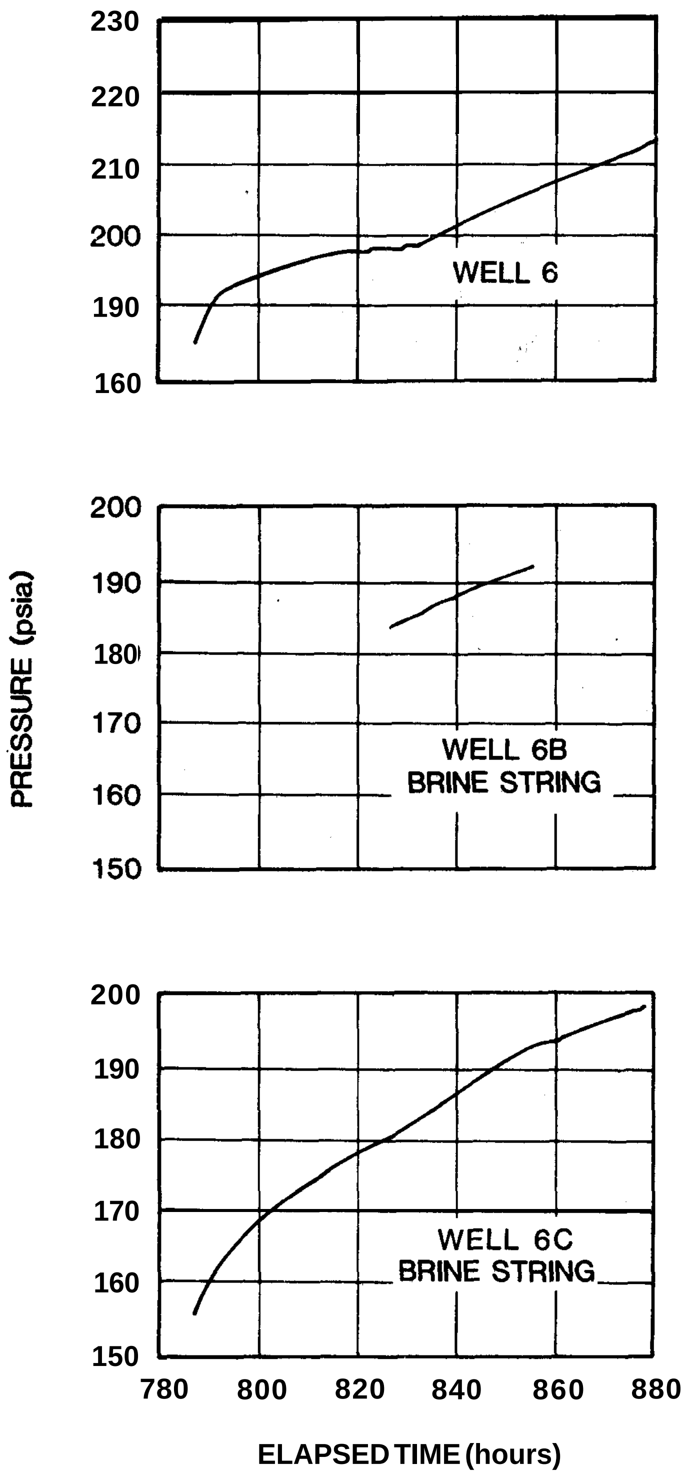


FIGURE 21 – WELLHEAD BRINE PRESSURES FOLLOWING CAVERN SHUT IN AT PRESSURE OF 150 PSIA

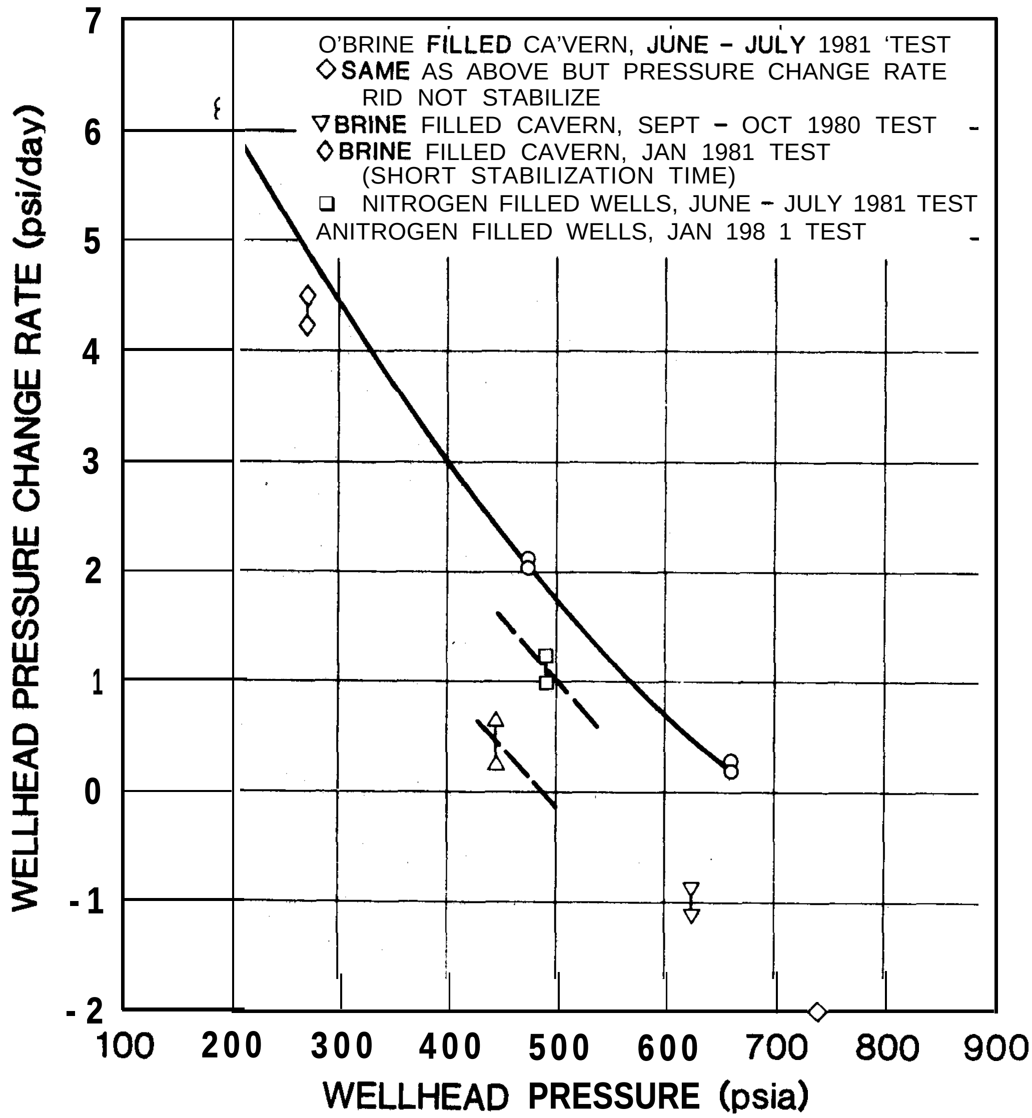


FIGURE 22 - WELLHEAD PRESSURE CHANGE RATE AT VARIOUS CAVERN SHUT IN PRESSURES

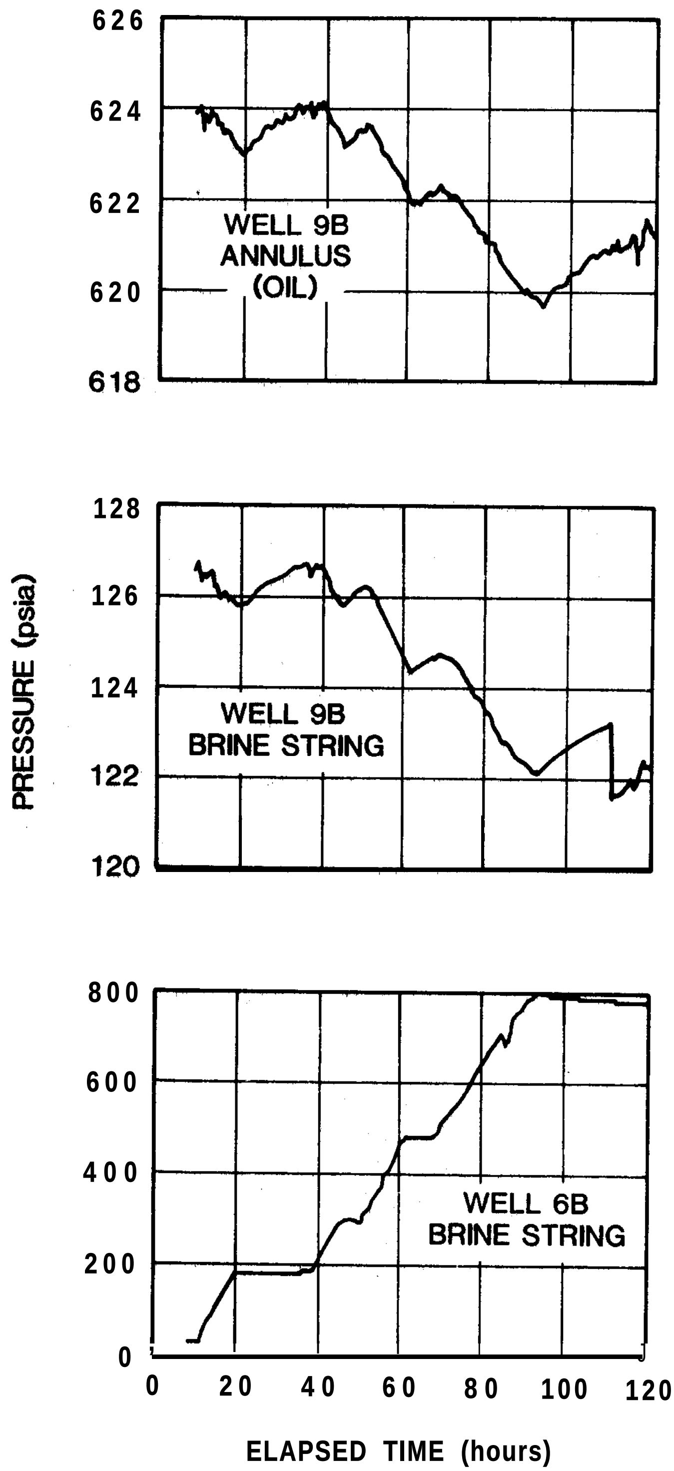


FIGURE 23 - EFFECT OF CAVERN 6 PRESSURIZATION ON CAVERN 9 PRESSURES

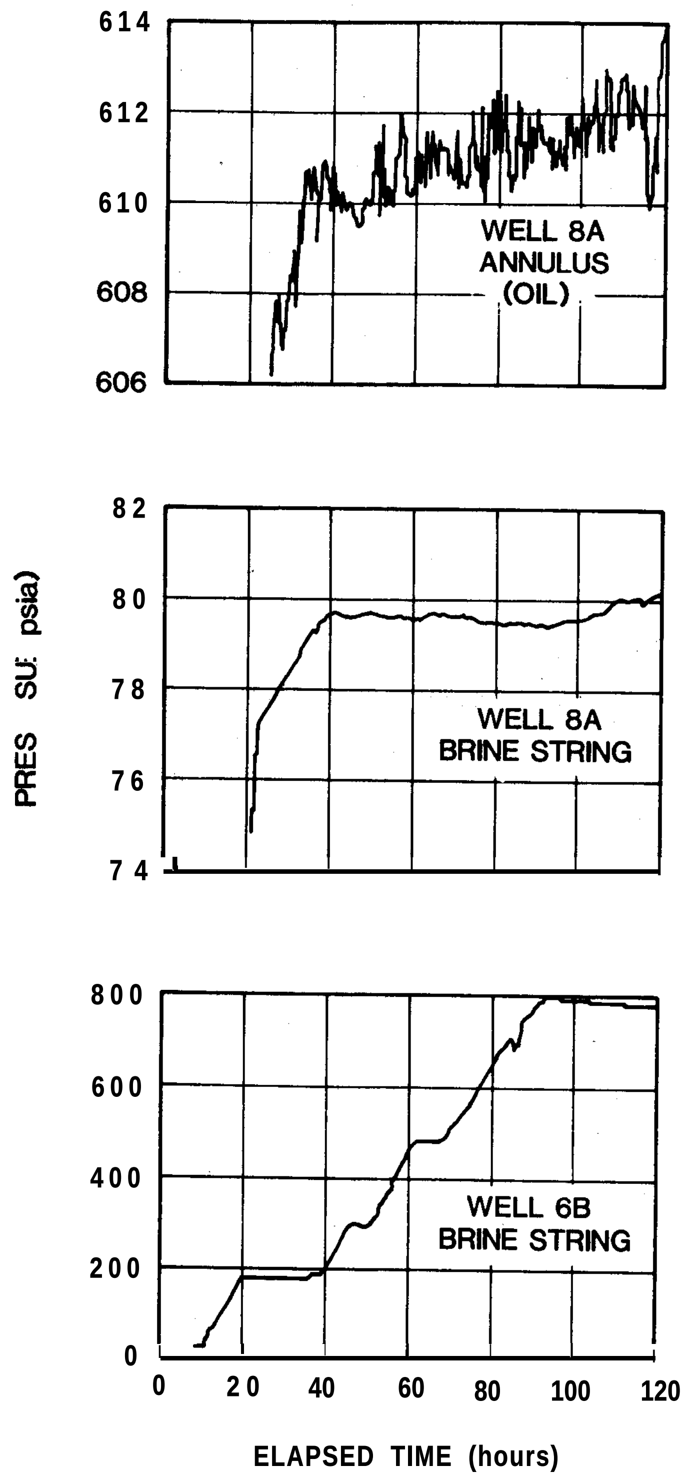


FIGURE 24 - EFFECT OF CAVERN 6 PRESSURIZATION ON CAVERN 8 PRESSURES

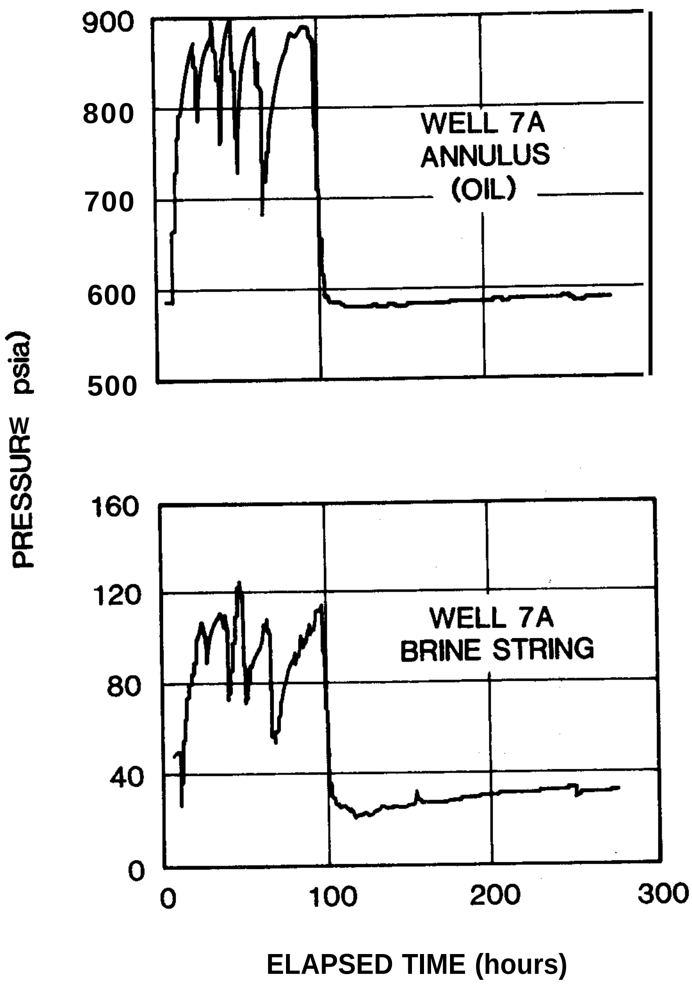


FIGURE 25 - CAVERN 7 PRESSURES DURING AND FOLLOWING OIL FILL

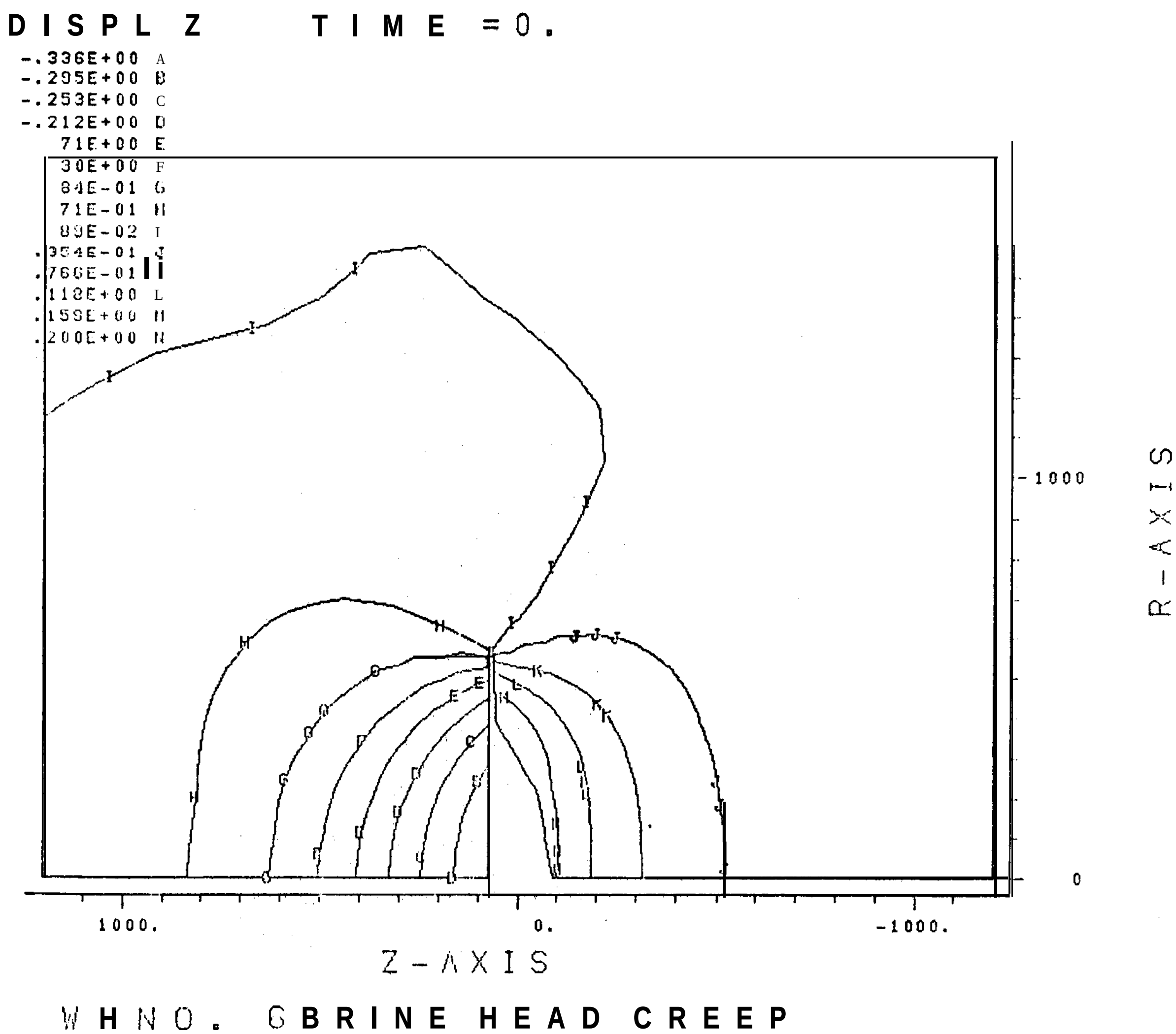

DISPL Z TIME =0.
-.336E+00 A
-.295E+00 B
-.253E+00 C
-.212E+00 D
71E+00 E
30E+00 F
84E-01 G
71E-01 H
89E-02 I
.354E-01 J
.766E-01
.118E+00 L
.159E+00 M
.200E+00 N
1000
0
R-AXIS
1000.
0.
-1000.
Z-AXIS
WHNO. 6BRINE HEAD CREEP

FIGURE A-1

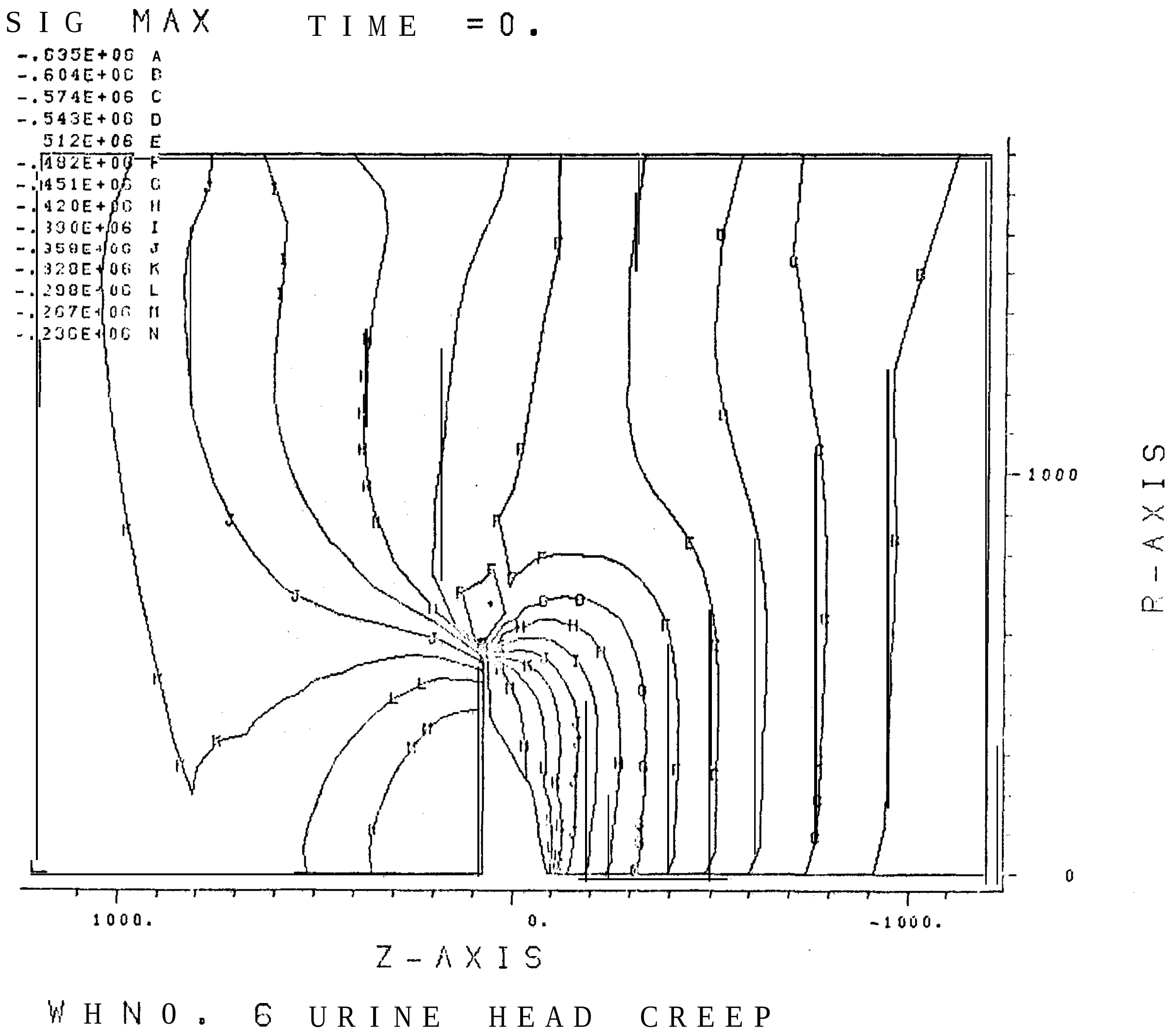

SIG MAX TIME =0.
-.635E+06 A
-.604E+06 B
-.574E+06 C
-.543E+06 D
.512E+06 E
-.482E+06 F
-.451E+06 G
-.420E+06 H
-.390E+06 I
-.359E+06 J
-.328E+06 K
-.298E+06 L
-.267E+06 M
-.236E+06 N
1000
0
R-AXIS
1000.
0.
-1000.
Z-AXIS
WHNO. 6 URINE HEAD CREEP

FIGURE A-2

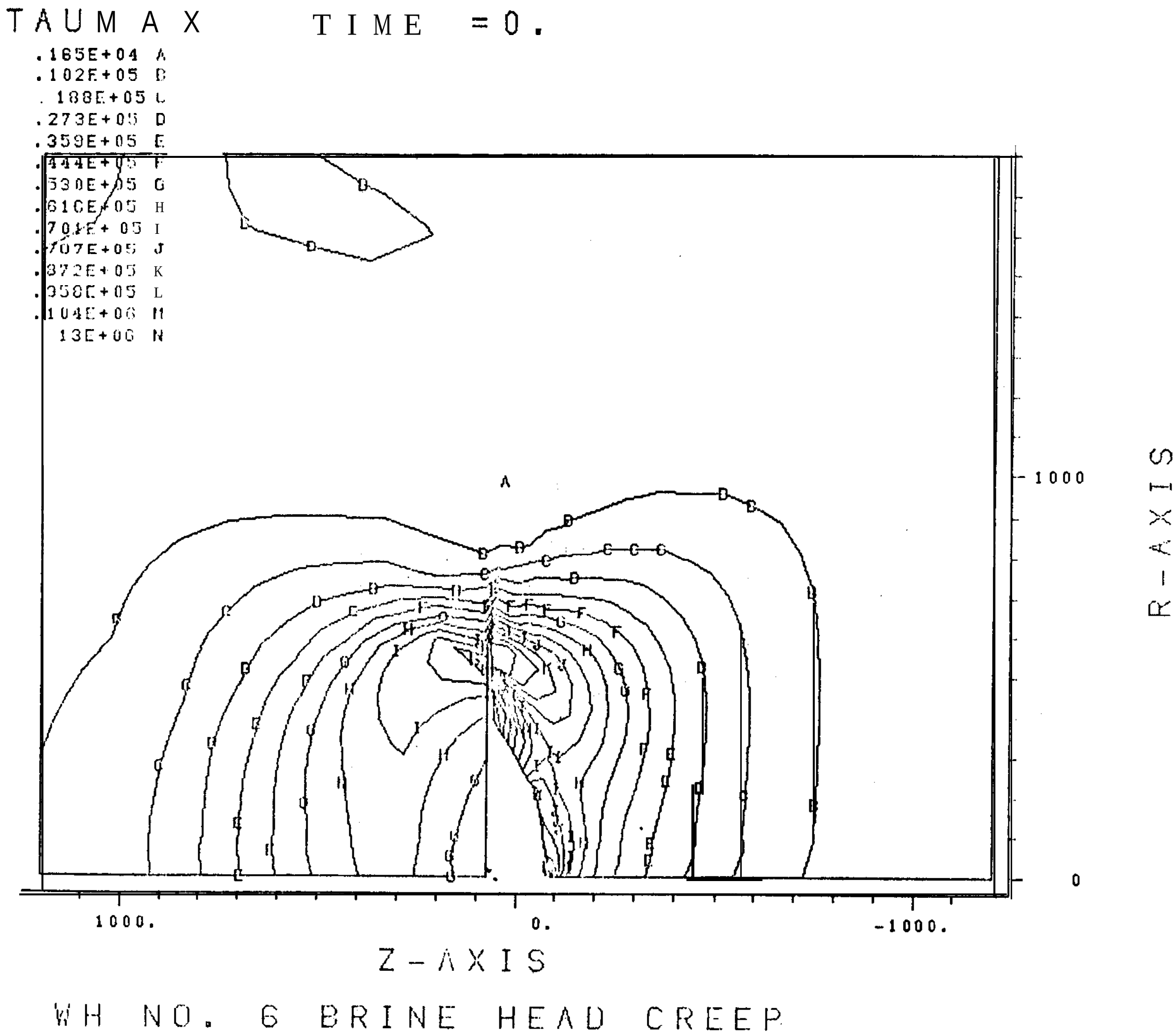
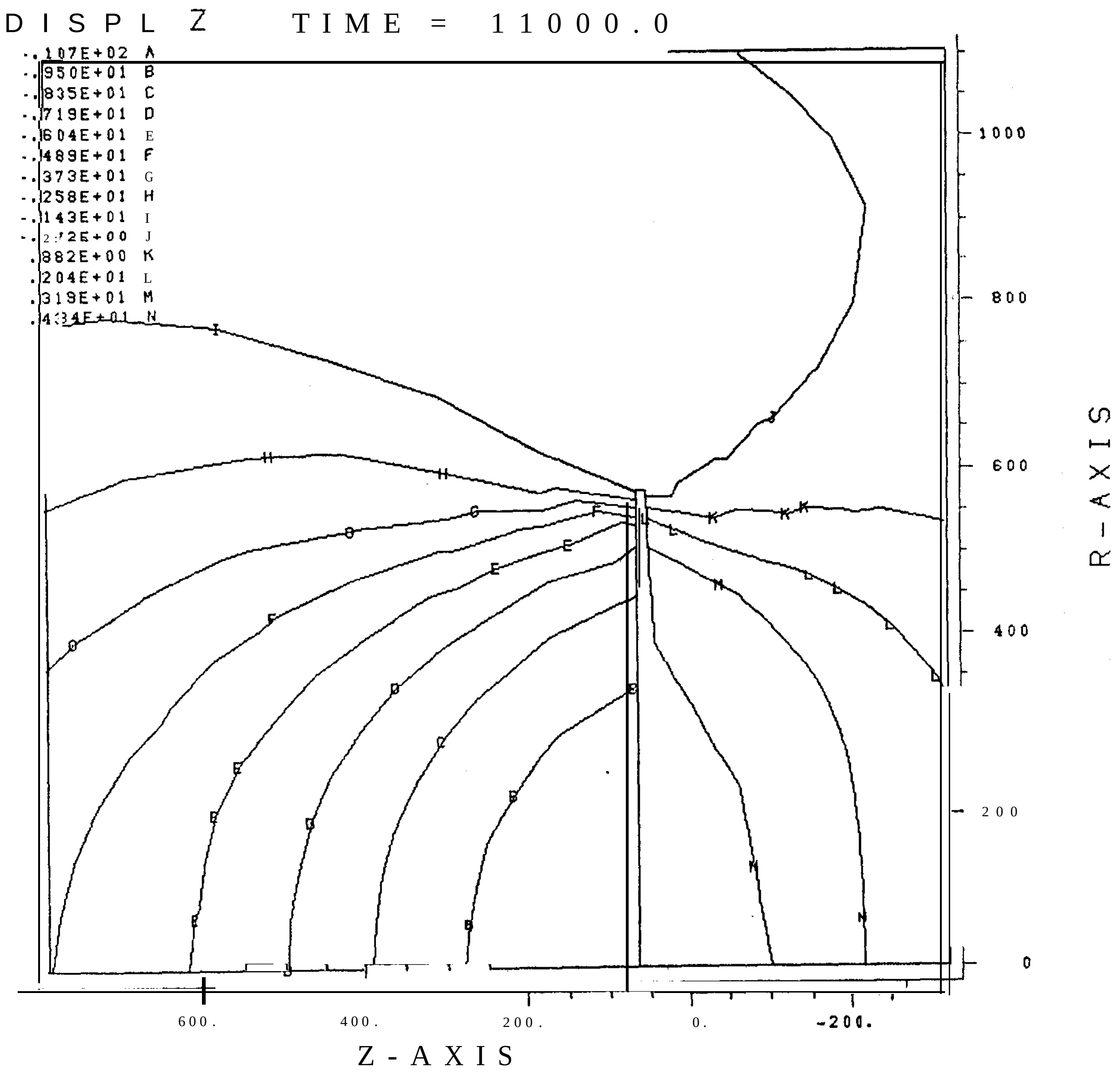

TAUMAX
TIME =0.
.165E+04 A
.102E+05 B
.188E+05 C
.273E+05 D
.359E+05 E
1000
0
R-AXIS
1000.
0.
-1000.
Z-AXIS
WH NO. 6 BRINE HEAD CREEP

FIGURE A-3



WH NO. 6 BRINE HEAD CREEP

FIGURE A-4

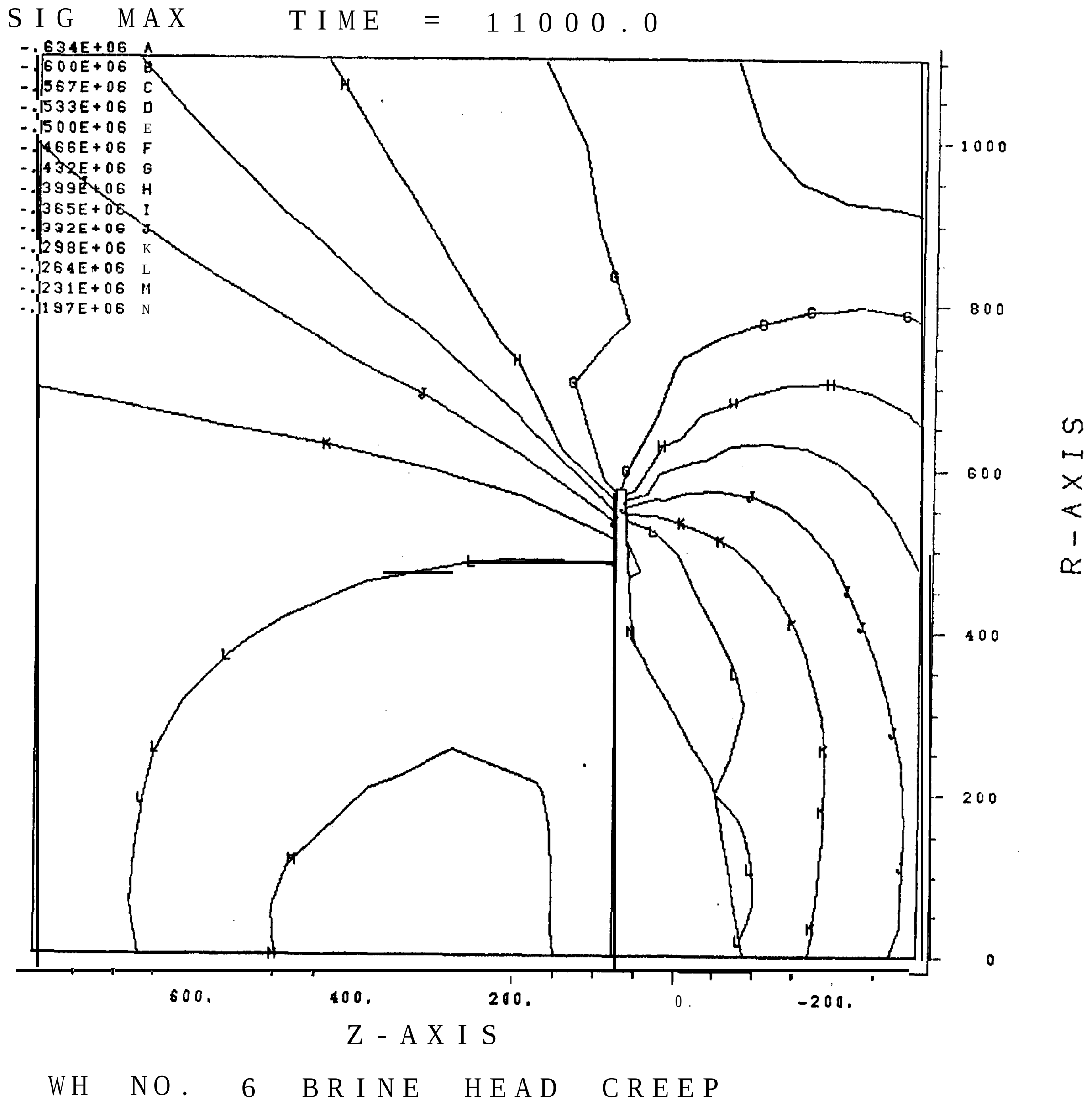
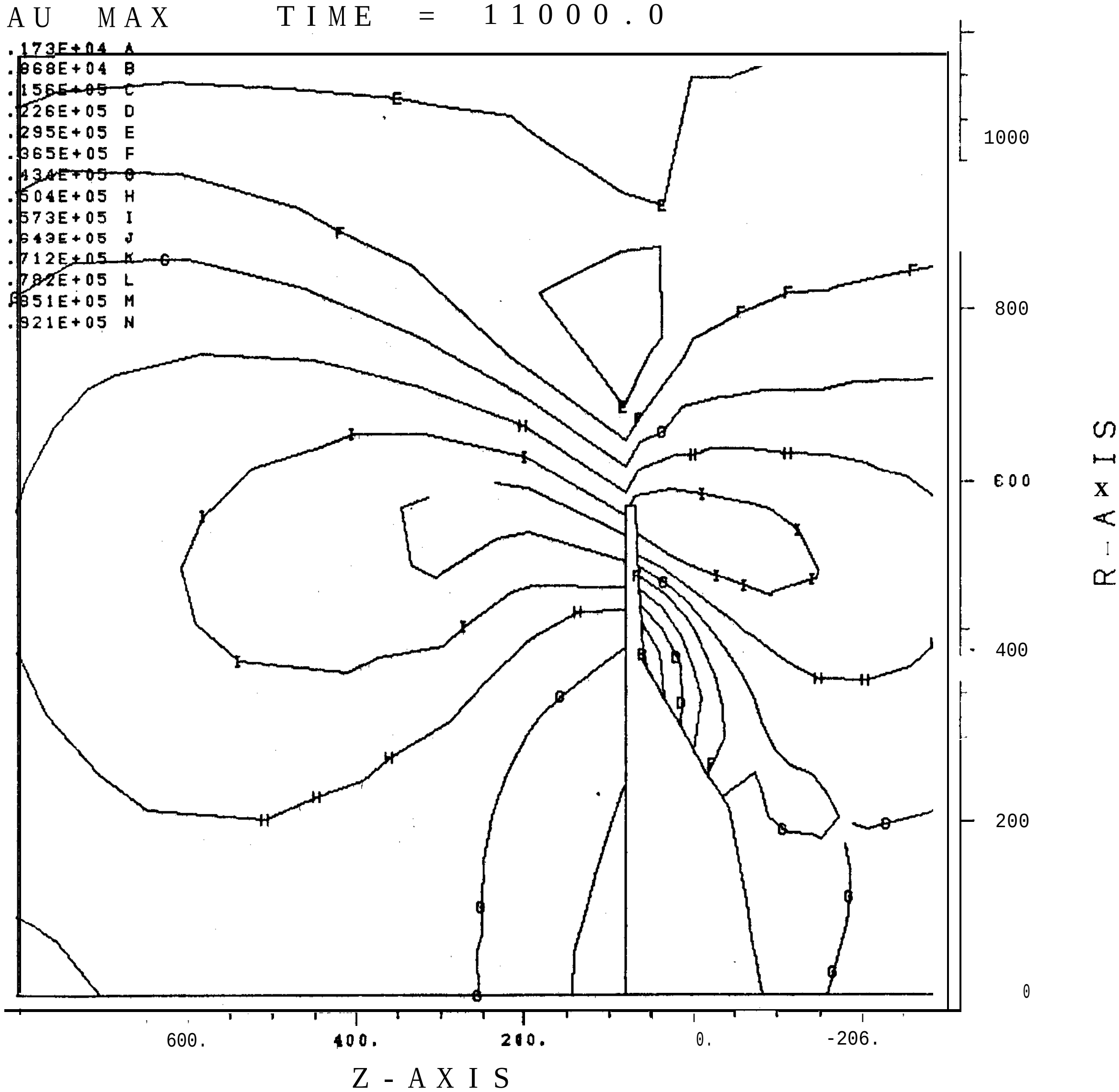

SIG MAX TIME = 11000.0
-.634E+06 A
-.600E+06 B
-.567E+06 C
-.533E+06 D
-.500E+06 E
-.466E+06 F
-.432E+06 G
-.399E+06 H
-.365E+06 I
-.332E+06 J
-.298E+06 K
-.264E+06 L
-.231E+06 M
-.197E+06 N
R-AXIS
Z-AXIS
WH NO. 6 BRINE HEAD CREEP

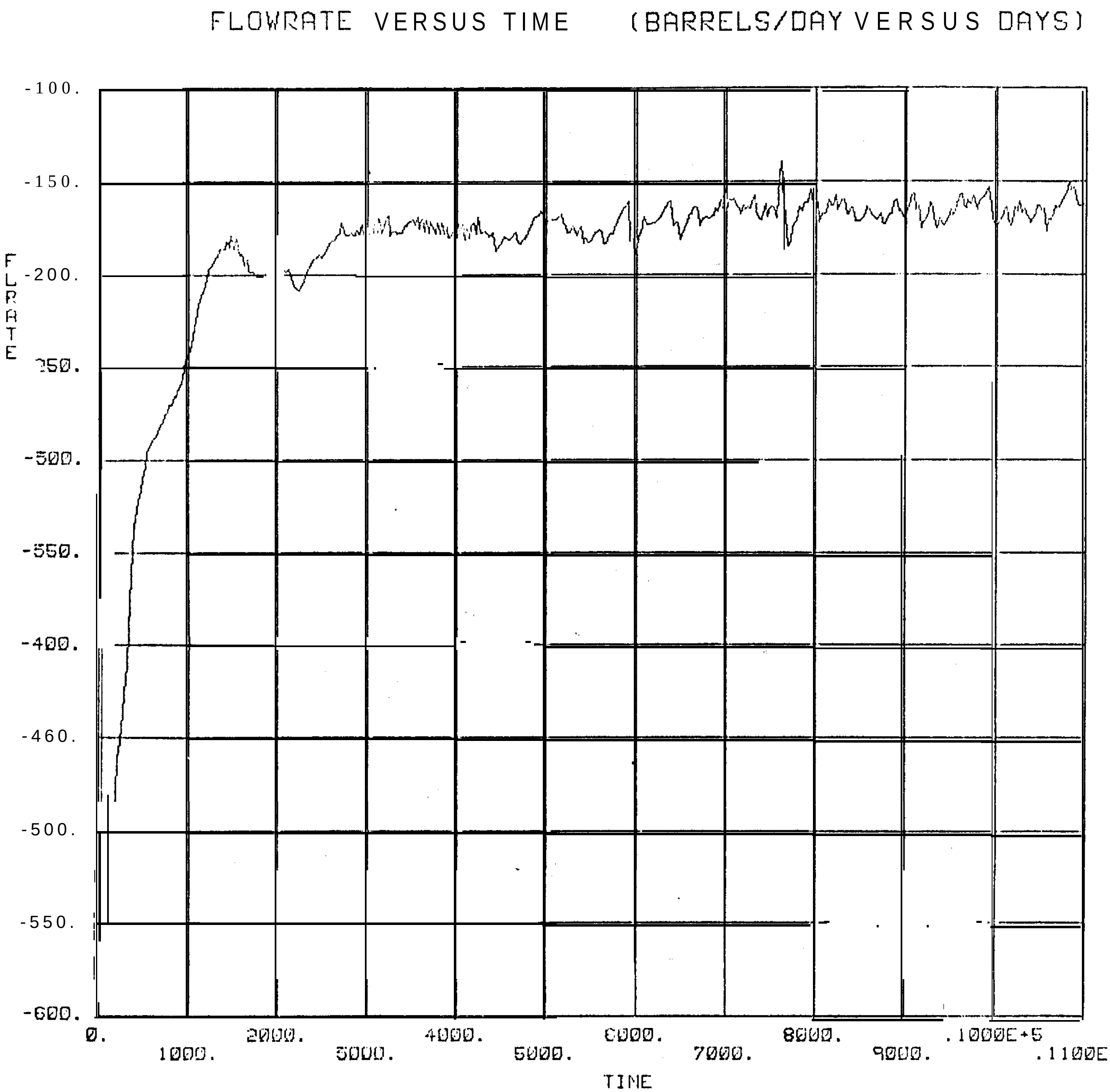
FIGURE A-5

TAU MAX TIME = 11000.0



WH NO. 6 BRINE HEAD CREEP

FIGURE A-6



H NO. 6 BRINE HEAD CREEP

FIGURE A-7